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By Environmental Improvement Board at 5:48 pm, Sep 07, 2021

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

CLEAN AIR ADVOCATES' NOTICE OF INTENT TO PRESENT REBUTTAL TESTIMONY

Pursuant to 20.1.1.302.A NMAC and the Procedural Order issued by the Hearing Officer in this matter, Tannis Fox, Western Environmental Law Center, and David R. Baake, Baake Law LLC, on behalf of Conservation Voters New Mexico, Diné C.A.R.E., Earthworks, National Parks Conservation Association, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, 350 New Mexico, and 350 Santa Fe ("Clean Air Advocates"), file this Notice of Intent to Present Rebuttal Testimony.

Joint Proposed *Revised* Amendments to Proposed 20.2.50 NMAC from EDF, Clean Air Advocates, Center for Civic Policy, and NAVA Education Fund

On July 28, 2021, Clean Air Advocates, along with the Environmental Defense Fund, Center for Civic Policy, and NAVA Education Project, filed Joint Proposed Amendments to Proposed 20.2.50 NMAC, along with direct testimony and exhibits in support.

After the initial filings, Oxy USA, Inc. ("Oxy"), a party in this proceeding, approached our coalition to see if we could find common ground on each other's proposals. We met over the course of several weeks and have agreed upon certain, but not all, provisions in the proposed rule. McCabe Reb. Test. at 2 [Clean Air Advocates' Ex. 23].

This development is important because the provisions we have agreed to would significantly improve and strengthen the rule proposed by the New Mexico Environment Department ("NMED"). Oxy supports Clean Air Advocates' four proposals, with certain modifications. Accordingly, our coalition is filing Joint Proposed *Revised* Amendments to

Proposed 20.2.50 NMAC that reflects these agreements, which is Clean Air Advocates' Exhibit 22.

Each of the four proposals supported by Oxy strengthens the rule proposed by the New Mexico Environment Department. These proposals would:

- Increase the frequency of leak detection and repair inspections at wellhead sites located within 1,000 feet of homes, schools, and businesses in order to better protect the health of frontline communities;
- Increase the timetable to retrofit pneumatic controllers to increase emission reductions from those devices, which are significant;
- Require emissions from completions and recompletions of wells to be captured instead of vented or flared; and
- Require automatic vessel measurement systems on new storage vessels to minimize venting of emissions from those devices.

It is significant that a major oil and gas operator in New Mexico has agreed to these stronger provisions, determining they are technically and economically feasible. We hope the Environmental Improvement Board will take note of this key development and consider and adopt these negotiated proposals. *Id.*

Rebuttal Testimony and Exhibits

In accordance with 20.1.1.302.A NMAC and the Procedural Order, Clean Air Advocates provide the following information.

1. Identify the person(s) for whom the witnesses will testify in rebuttal:

The two witnesses identified below, David McCabe, Ph.D. and Lee Ann L. Hill, MPH, will testify in rebuttal on behalf of Clean Air Advocates.

2. Identify each technical witness the person intends to present for rebuttal, and state the qualifications of that witness, including a description of their educational and work background:

Clean Air Advocates intend to present:

- David McCabe, Ph.D., Atmospheric Scientist, Clean Air Task Force, who provided direct testimony on behalf of Clean Air Advocates in this matter and whose educational and work background is set forth in his curriculum vitae, which is Clean Air Advocates' Exhibit 2; and
- Lee Ann L. Hill, MPH, Senior Scientist, Physicians, Engineers, and Scientists for Healthy Energy, whose educational and work background is set forth in her curriculum vitae, which is Clean Air Advocates' Exhibit 24.

3. Include a copy of the direct testimony of each technical witness in narrative form:

Clean Air Advocates submits the written rebuttal testimony of Dr. McCabe in Exhibit 23 and Ms. Hill in Exhibit 25.

4. Include the text of any recommended modifications to the proposed regulatory change:

A text of the modifications to proposed 20.2.50 NMAC proposed by Clean Air Advocates is attached as Exhibit 22.

5. List and attach all exhibits anticipated to be offered at the hearing:

Below is a list of all direct and rebuttal exhibits to be offered by Clean Air Advocates in support of its testimony. Clean Air Advocates' direct exhibits were filed July 28, 2021. Clean Air Advocates' rebuttal exhibits are attached. Both sets of exhibits have a table of contents, accessible by clicking on the "bookmarks" tab in Adobe Acrobat. Clean Air Advocates reserves the right to offer sur-rebuttal testimony and exhibits.

Exhibit	Description
	DIRECT EXHIBITS
Ex. 1	Joint Proposed Amendments to Proposed 20.2.50 NMAC
Ex. 2	Curriculum Vitae of David McCabe, Ph.D.
Ex. 3	Direct Testimony of David McCabe, Ph.D.
Ex. 4	Zero Emission Technologies for Pneumatic Controllers in the USA, Carbon Limits (Aug. 1, 2016)
Ex. 5	Conservation Groups' Initial Economic Impact Analysis Non-Emitting Pneumatics - 2020 [Colorado rulemaking]
Ex. 6	Pneumatics Cost Spreadsheet, Carbon Limits
Ex. 7	Cap-On British Columbia Oil and Gas Methane Emissions Field Study (2019)
Ex. 8	Pneumatic Controller Task Force Report to AQCC, CO Air Pollution Control Div., Dept. of Public Health and Env't. (June 1, 2020)
Ex. 9	Resume of Don Schreiber
Ex. 10	Direct Testimony of Don Schreiber
Ex. 11	Photograph of blewie line in operation in San Juan Basin in 1958
Ex. 12	Photographs of blewie line completions near Schreiber ranch around 2005 or 2006
Ex. 13	Lessons Learned from Natural Gas STAR Partners: Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells, EPA (2011)
Ex. 14	Reduced Emissions Completions and Smart Automation, Producers and Processors Technology Workshop, NMOGA and EPA Natural Gas STAR Program (Feb. 21, 2006)
Ex. 15	Reducing Methane Emissions form Production Wells: RECs, Producers Technology Workshop, ConocoPhillips, NMED, and NMOGA (May 11, 2010)
Ex. 16	Williams Northeast Supply Enhancement, Natural Gas: The Facts
Ex. 17	"Natural Gas and Green Completions in a Nutshell," Energy in Depth (Nov. 26, 2012)
Ex. 18	Photographs from Hilcorp recompletion of San Juan 28-6 Unit 143 (Mar. 8, 2018)
Ex. 19	5 CCR § 1001-9:D.VI.D and Statement of Basis
Ex. 20	2 CCR § 404-1:903.c
Ex. 21	Appendix B: Statement of Basis of Colorado Oil and Gas Comm'n, for 2 CCR § 404-1; excerpts for 2 CFR § 404-1:903.c
	REBUTTAL EXHIBITS
Ex. 22	Joint Proposed Revised Amendments to Proposed 20.2.50 NMAC
Ex. 23	Rebuttal Testimony of David McCabe, Ph.D.
Ex. 24	Curriculum Vitae of Lee Ann L. Hill, MPH
Ex. 25	Rebuttal Testimony of Lee Ann L. Hill, MPH

Respectfully submitted,

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Certificate of Service

I certify that a copy of the foregoing pleading was emailed to the following on September 7, 2021:

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JOINT PROPOSED REVISED AMENDMENTS TO PROPOSED 20.2.50 NMAC FROM

ENVIRONMENTAL DEFENSE FUND

AND

CONSERVATION VOTERS NEW MEXICO, DINÉ C.A.R.E., EARTHWORKS, NATIONAL PARKS CONSERVATION ASSOCIATION, NATURAL RESOURCES DEFENSE COUNCIL, SAN JUAN CITIZENS ALLIANCE, SIERRA CLUB, 350 NEW MEXICO, AND 350 SANTA FE

AND

CENTER FOR CIVIL POLICY AND NAVA EDUCATION PROJECT

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. Once a source becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in this Part.
[20.2.50.2 NMAC – N, XX/XX/2021]

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

20.2.50.5 EFFECTIVE DATE: Month XX, 2021, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

B. "Auto-igniter" means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

C. "Bleed rate" means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller.

D. "Calendar year" means a year beginning January 1 and ending December 31.

E. "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

F. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere.

G. "Commencement of operation" means for an oil and natural gas wellhead, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol

I. **"Connector"** means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

J. **"Construction"** means fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources.

K. **"Custody transfer"** means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.

L. **"Control device"** means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, air fuel ratio controllers (AFRs), catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.

M. **"Department"** means the New Mexico environment department.

N. **"Downtime"** means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation.

O. "**Drilling**" or "**drilled**" means the process to bore a hole to create a well for oil and/or natural gas production.

P. **"Drill-out"** means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore cleanup.

Q. **"Enclosed combustion device"** means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater.

R. **"Existing"** means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

S. **"Flowback"** means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

T. **"Flowback vessel"** means a vessel that contains flowback

U. **"Gathering and boosting station"** means a permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage.

V. "**Hydraulic fracturing**" means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

W. "**Hydraulic refracturing**" means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

X. **"Glycol dehydrator"** means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

Y. **"Hydrocarbon liquid"** means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons.

Z. "Inactive wellhead site" means a wellhead site where the well is not being used for beneficial purposes, such as production or monitoring, and is not being drilled, completed, repaired or worked over.

AA. "Injection wellhead site" means a wellhead site where the well is used for the injection of air, gas, water or other fluids into an underground stratum.

BB. **"Liquid unloading"** means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

CC. **"Liquid transfer"** means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport.

DD. “Local distribution company custody transfer station” means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

EE. “Natural gas compressor station” means one or more compressors designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline.

FF. “Natural gas-fired heater” means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

GG. “Natural gas processing plant” means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

HH. “New” means constructed or reconstructed on or after the effective date of this Part.

II. "Occupied area" means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

JJ. “Operator” means the person or persons responsible for the overall operation of a stationary source.

KK. “Optical gas imaging (OGI)” means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

LL. “Owner” means the person or persons who own a stationary source or part of a stationary source.

MM. “Permanent pit” means a pit used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

NN. “Pneumatic controller” means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature.

OO. “Pneumatic diaphragm pump” means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

PP. “Potential to emit (PTE)” means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

QQ. “Pre-production operations” means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

RR. “Produced water” means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

SS. “Produced water management unit” means a recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

TT. “Qualified Professional Engineer” means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

UU. “Reciprocating compressor” means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

VV. “Reconstruction” means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

WW. **"Recycling facility"** means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

XX. **"Responsible official"** means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

YY. **"Satellite facility"** means a liquid storage facility located downstream of primary separation but prior to sales.

ZZ. **"Small business facility"** means, for the purposes of this Part, a source that is independently owned or operated by a company that is a not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers.

AAA. **"Startup"** means the setting into operation of air pollution control equipment or process equipment.

BBB. **"Stationary Source"** or **"source"** means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

CCC. **"Storage vessel"** means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

DDD. **"Temporarily abandoned wellhead site"** means an inactive wellhead site where the well's completion interval has been isolated. The completion interval is the reservoir interval that is open to the borehole and is isolated when tubing and artificial equipment has been removed and a bottom plug has been set.

EEE. **"Vessel measurement system"** means equipment and methods used to determine the quantity of the liquids inside a vessel (including a flowback vessel) without requiring direct access through the vessel thief hatch or other opening.

FFF. **"Well workover"** means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

GGG. **"Wellhead site"** means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.

[20.2.50.7 NMAC - N, XX/XX/2021]

20.2.50.8 **SEVERABILITY:** If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.

[20.2.50.8 NMAC - N, XX/XX/2021]

20.2.50.9 **CONSTRUCTION:** This Part shall be liberally construed to carry out its purpose.

[20.2.50.9 NMAC - N, XX/XX/2021]

20.2.50.10 **SAVINGS CLAUSE:** Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.

[20.2.50.10 NMAC - N, XX/XX/2021]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.
[20.2.50.11 NMAC - N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau.
[20.2.50.12 NMAC - N, XX/XX/2021]
[The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

20.2.23.13-20.2.23.110 [**RESERVED**]

20.2.50.111 APPLICABILITY:

A. This Part applies to crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water in the areas specified in 20.2.50.2 NMAC and are located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station.

B. In determining if any source is subject to this Part, including a small business facility as defined in this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE calculation certified by a qualified professional engineer or in-house engineer with expertise regarding the calculation of PTE. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

D. Oil refinery and transmission pipelines are not subject to this Part.
[20.2.50.111 NMAC - N, XX/XX/2021]

20.2.50.112 GENERAL PROVISIONS:

A. General requirements:

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the department. For sources constructed prior to 1980 for which no manufacturer specifications and maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule sufficient to operate and maintain such units in good working order. The owner or operator shall keep such maintenance schedules on file and make them available to the department upon request.

(2) Sources subject to emission standards or requirements under this Part shall be operated to minimize emissions of air contaminants, including VOC and NO_x.

(3) The owner or operator shall manage the source's record of data in a database that is able to generate a Compliance Database Report (CDR) adequate to provide the department with compliance assurance. The CDR is an electronic report generated by the owner or operator's database and submitted to the department upon request. The format of the CDR shall be determined by the department.

(4) The CDR is a report distinct from the owner or operator's database. The department does not require access to the owner or operator's database, only the CDR.

(5) If read by the owner or operator's authorized representative, the Equipment Monitoring Tags (EMT) for sources that utilize EMT shall access the owner or operator's database record for that source.

~~(3)~~(6) The owner or operator shall contemporaneously track each compliance event for each source subject to the requirements of this Part, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.

(b) data required by this Part shall be maintained in the database for at least five years.

(7~~3~~) Within two years of the effective date of this Part, owners and operators of a source utilizing an ~~requiring an Equipment Monitoring Tag (~~EMT~~)~~ system for compliance assurance shall physically tag each unit with an EMT, the format of which shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This unique identifier shall act as an index to the source's record of the data required by this Part. The EMT shall be maintained by the owner or operator, and data in the EMT shall provide at a minimum, the following information:

(a) unique unit identification number;
(b) location of the source;
(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);
(d) for each source, the VOC (and NO_x, if applicable) PTE in lbs./hr. and tpy;
(e) for a control device, the controlled VOC and NO_x PTE in lbs./hr. and tpy;
(f) make, model, and serial number; and
(g) a link to the manufacturer's maintenance schedule or repair recommendations.

(8~~4~~) The EMT shall be installed and maintained by the owner or operator of the facility.

(9~~5~~) The EMT shall be of a format scannable by an owner or operator's authorized representatives and, upon scanning, shall provide unique identifier that shall index the source's record of the data required by this Part.

~~**(6)** The owner or operator shall manage the source's record of data in a database that is able to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or operator's database and submitted to the department upon request. The format of the CDR shall be determined by the department.~~

~~**(7)** The CDR is a report distinct from the owner or operator's database. The department does not require access to the owner or operator's database, only the CDR.~~

~~**(8)** If read by the owner or operator's authorized representative, the EMT shall access the owner or operator's database record for that source.~~

~~**(9)** The owner or operator shall contemporaneously track each compliance event for each source subject to the EMT requirements of this Part, and shall comply with the following:~~

~~**(a)** data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.~~

~~**(b)** data required by this Part shall be maintained in the database for at least five years.~~

(10) The department may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department.

B. Monitoring requirements:

(1) Sources subject to emission standards and monitoring (e.g. inspection, testing, parametric monitoring) requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different schedule is specified in the Section applicable to that source type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

(2) An owner or operator may submit for the department's review and approval an equally effective, enforceable, and equivalent alternative monitoring strategy. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements required under the applicable Section and shall not operate under an alternative monitoring strategy until it has been approved by the department.

(a) For sources that implement alternative monitoring strategies, initial scanning of the EMT before a monitoring event and final scanning of an EMT at the end of the monitoring event are not required provided that electronic data retrieved from the monitoring event satisfies the requirements found at 20.2.50.112(B)(3)(a)-(e) NMAC and is uploaded to the owner or operator's database following the monitoring event.

(3) ~~Each~~ For sources that utilize an EMT, each ~~-~~monitoring event (e.g. testing, inspection, parametric monitoring) shall be initiated by an initial scanning of the EMT, the results of which shall then be directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include:

(a) date and time of the testing, monitoring, or inspection event;
(b) name of the personnel conducting the testing, monitoring, or inspection;
(c) identification number and type of unit;
(d) a description of any maintenance or repair activity conducted; and
(e) results of testing, monitoring, or inspection as required under this Part.

C. Recordkeeping requirements:

(1) Within three business days of a monitoring event, an electronic record shall be made of the monitoring event and shall include the following data:

(a) date and time of the testing, monitoring, or inspection event;
(b) name of the personnel conducting the testing, monitoring, or inspection;
(c) identification number and type of unit;
(d) a description of any maintenance or repair activity conducted; and
(e) results of any testing, monitoring, or inspections required under this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years. The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.

~~**(3)** Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for for five years.~~

D. Reporting requirements: Within 24 hours of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

[20.2.50.112 NMAC - N, XX/XX/2021]

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meets the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual NOx and VOC emissions are reduced by at least ninety-five percent per year.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES

CONSTRUCTED, RECONSTRUCTED, OR INSTALLED BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	>1,000	0.50 g/bhp-hr	47 ppmvd @ 15% O_2 or 93% reduction	0.70 g/bhp-hr
Rich-burn	>1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, OR INSTALLED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO_x	CO	NMNEHC (as propane)
Lean-burn	>500 - <1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥1,000	0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with control	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than two years from the effective date of this Part:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <5,000	50	50	9
≥5,000 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction

For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO_x (ppmvd @15% O_2)	CO (ppmvd @ 15% O_2)	NMNEHC (as propane, ppmvd @15% O_2)
≥1,000 and <5,000	25	25	9
≥5,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(9) The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.

(10) The owner or operator of an emergency use engine that is operated less than 100 hours per year is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

C. Monitoring requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall meet the minimum manufacturer recommended maintenance schedule. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:

(a) routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and

(b) unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer or supplier recommended maintenance schedules, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(3) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated by performing an initial emissions test, followed by annual tests, for NO_x, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

(a) emissions testing events shall be conducted at ninety percent or greater of the unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(4) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine operated for less than 100 hours per year shall monitor the hours of operation by a non-resettable hour meter.

(6) An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(7) Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and EMT for the engine or turbine;

(b) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule;

(c) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time of an inspection, maintenance or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the personnel conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

(v) a description of maintenance or repair activity conducted; and

(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine. The records shall include:

(a) the make, model, serial number, and EMT for the tested engine or turbine;

(b) the date and time of sampling or measurements;

(c) the date analyses were performed;

(d) the name of the personnel and the qualified entity that performed the analyses;

(e) the analytical or test methods used;

(f) the results of analyses or tests;

(g) for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine operated less than 100 hours per year shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate the ninety-five percent emission reduction requirement is met.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.113 NM–C - N, XX/XX/2021]

20.2.50.114 COMPRESSOR SEALS:

A. Applicability:

(1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.

(2) Reciprocating compressors located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.

B. Emission standards:

(1) The owner or operator of an existing centrifugal compressor shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(2) The owner or operator of an existing reciprocating compressor shall, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(3) The owner or operator of a new centrifugal compressor shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-eight percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:

(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, a recovery system, fuel cell or a process stream.

(5) The owner or operator of a centrifugal or reciprocating compressor shall install an EMT on the compressor in accordance with 20.2.50.112 NMAC.

(6) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.115 NMAC.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates under negative pressure and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location of the centrifugal compressor;

(b) the date of construction, reconstruction, or modification of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the personnel conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and identification number of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location of the reciprocating compressor;

(b) the date of construction, reconstruction, or modification of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:

(i) the number of hours of operation since initial startup or the last rod packing replacement;

(ii) the records of pressure in the rod packing emissions collection system; and

(iii) the time and date of the inspection, the personnel conducting the inspection, a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed, a description of problems observed during the inspection, and a description and date of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.114 NM–C - N, XX/XX/2021]

20.2.50.115 CONTROL DEVICES:

A. Applicability: These requirements apply to control devices as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NO_x.

(3) The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.

(4) The owner or operator shall inspect control devices used to comply with this Part at least monthly to ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.

(5) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(6) The owner or operator of a closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic controller or pump, ~~or~~ storage vessel, or flowback vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate all emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected equipment are routed to the control device or process; and

(c) have the closed vent system certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of the closed vent system in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: “I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete.”

(7) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include:

(a) manufacturer name, make, and model;

(b) maximum heating value for an open flare, ECD, or TO;

(c) maximum rated capacity for an open flare, ECD/TO, or VRU;

(d) gas flow range for an open flare, ECD, or TO; and

(e) designed destruction or vapor recovery efficiency.

C. Requirements for open flares:

(1) Emission standards:

(a) the flare shall combust the gas sent to the flare and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (C) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly.

(e) the owner or operator shall repair the flare within three business days of any alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes;

(d) prior to an inspection or monitoring event, the EMT on the flare shall be scanned and the required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the personnel conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the gas analysis for the gas being flared, including VOC content and heating value; and

(e) any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip an ECD/TO with a continuous pilot flame or an auto-igniter. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes.

(c) prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of an alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;

(b) the result of the U.S. EPA method 22 observation; and

(c) the results of gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or, alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event in accordance with 20.2.50.112 NMAC, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator shall record the type of redundant control device used during VRU downtime.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

F. Recordkeeping requirements: The owner or operator of a control device shall maintain a record of the following:

(1) the certification of the closed vent system as required by this Part; and

(2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

~~**H. Requirements for flowback vessels and preproduction operations:**~~

~~**(1)** Emissions standards:~~

~~**(a)** the owner or operator of a well that begins flowback on or after [effective date of this Part] must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to an operating control device that achieves a hydrocarbon control efficiency of at least 95 percent. If a TO or ECD is used, it must have a design destruction efficiency of at least 98 percent for hydrocarbons.~~

~~**(i)** the owner or operator shall use enclosed, vapor-tight flowback vessels with an appropriate pressure relief system to be used only as necessary to ensure safety.~~

~~**(ii)** flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback~~

~~**(iii)** the owner or operator shall use a tank measurement system to determine the quantity of liquids in the flowback vessel(s).~~

~~**(A)** Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).~~

~~**(B)** Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section 115.H(1)(iv)(i).~~

~~**(2)** Monitoring~~

~~**(a)** Owners and or operators of a well with flowback that begins on or after the effective date of 20.2.50 NMAC, must conduct daily visual inspections of the flowback vessel and any associated equipment, including~~

~~**(i)** visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.~~

~~**(ii)** visual inspection or monitoring of the control device to ensure that it is operating.~~

~~**(iii)** visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open.~~

~~**(3)** Recordkeeping~~

~~**(a)** The owner or operator of each flowback vessel subject to Section 115.H(1). must maintain records for a period of five (5) years and make them available to the NMED upon request, including~~

~~**(i)** the API number of the well and the associated facility location, including latitude and longitude coordinates.~~

~~**(ii)** the date and time of the onset of flowback.~~

~~**(iii)** the date and time the flowback vessels were permanently disconnected, if applicable.~~

~~**(iv)** the date and duration of any period where the control device is not operating.~~

~~**(v)** records of the inspections required in Section 115.H(2), including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).~~

[20.2.50.115 NM–C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements and the monitoring requirements in 20.2.50.112 NMAC:

(1) The owner or operator of a facility with an annual average daily production of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors;

(d) any positive detection during the AVO inspection shall be considered a leak; and

(e) a leak discovered by an AVO inspection shall be tagged with a visible tag and reported to management or their designee within three calendar days.

(2) The owner or operator of a facility with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for wellhead sites or tank battery facilities:

(i) annually at facilities with a PTE less than two tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.

(b) for gathering and boosting sites, gas processing plants, and transmission compressor stations:

(i) quarterly at facilities with a PTE less than 25 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

(c) for wellhead sites within 1,000 feet of an occupied area:

(i) quarterly at facilities with a PTE less than 5 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 5 tpy VOC.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21;

(b) the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but nor more than, 10,000 ppm methane or n-hexane; and

(c) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

(7) Owners and operators with wellhead sites subject to the requirements contained in Subparagraph (c) of Paragraph (3) of Subsection (C) of 20.2.50.116 NMAC must conduct an evaluation to determine applicability within 30 days of constructing a new wellhead site and annually within 90 days of the effective date of this Part for existing wellhead sites. Homeowners may contact NMED to request an owner or operator conduct the evaluation required by this Part.

(8) The leak survey requirements of Paragraphs (3) to (6) of Subsection (C) of 20.2.50.116 NMAC shall not apply to facilities where leak surveys are not anticipated to result in emissions reductions. Such facilities include satellite facilities, injection wellhead sites, and temporarily abandoned wellhead sites.

(9) The owner or operator of a wellhead site that becomes an inactive wellhead site after the effective date of this Part must complete the next inspection required under Paragraph (3) of Subsection (C) of 20.2.50.116 NMAC no sooner than 30 days after the site becomes an inactive wellhead site. Following this inspection, the owner or operator of an inactive wellhead site shall conduct the inspections required by Paragraph (3) of Subsection (C) of 20.2.50.116 NMAC annually.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) proposed alternative monitoring plans may utilize alternative monitoring methods.

(~~a~~b) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(~~b~~c) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(~~c~~d) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.C NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component until the component has been repaired;

(2) leaks shall be repaired within 15 days of discovery, except for leaks detected using OGI, which shall be repaired within seven days of discovery;

(3) the equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 15 days of discovery, or within seven days for a leak detected using OGI, without a process unit shutdown, the leak may be designated “Repair delayed,” and must be repaired before the end of the next process unit shutdown.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location;

(b) date of inspection;

(c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);

(d) name of the personnel performing the inspection;

(e) a description of any leak requiring repair or a note that no leak was found; and

(f) whether a visible flag was placed on the leak or not;

(2) The owner or operator shall keep the following record for any leak that is detected:

(a) the date the leak is detected;

(b) the date of attempt to repair;

(c) for a leak with a designation of “repair delayed” the following shall be recorded:

(i) reason for delay if a leak is not repaired within the required number of days after discovery;

(ii) signature of the authorized representative who determined that the repair could not be implemented without a process unit shutdown;

(d) date of successful leak repair;

(e) date the leak was monitored after repair and the results of the monitoring; and

(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: Liquid unloading operations including down-hole well maintenance events at natural gas wells are subject to the requirements of 20.2.50.117 NMAC.

B. Emission standards:

(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for liquid unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) reduce wellhead pressure before blowdown;

(b) monitor manual liquid unloading in close proximity to the well or via remote telemetry; and

(c) close well head vents to the atmosphere and return the well to normal production operation as soon as practicable.

(3) The owner or operator of a natural gas well shall use one of the following methods to reduce emissions during an unloading event:

(a) installation and use of a plunger lift;

(b) installation and use of an artificial lift engine; or

(c) installation and use of a control device.

(4) The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during liquid unloading:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the storage vessel or atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a liquid unloading event.

(3) A liquid unloading event shall include the scanning of the EMT and monitoring data entry in accordance with the requirements of 20.2.50.112 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following records for liquid unloading:

(a) identification number and location of the well;

(b) date the liquid unloading was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation);

(e) duration of venting to the storage vessel or atmosphere;

(f) a description of the management practice used to minimize release of VOC emissions before and during the liquid unloading;

(g) the type of control device used to control VOC emissions during the liquid unloading; and

(h) a calculation of the VOC emissions vented during the liquid unloading based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.117 NMAC - N, XX/XX/2021]

20.2.50.118 GLYCOL DEHYDRATORS:

A. Applicability: Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.118 NMAC.

B. Emission standards:

(1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank no later than two years after the effective date. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still vent and flash tank upon startup. If a combustion control device is used, the combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

(3) The owner or operator of a glycol dehydrator shall comply with the following requirements:

(a) still vent and flash tank emissions shall be routed at all times to the reboiler firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream or natural gas gathering pipeline;

(b) if a VRU is used, it shall consist of a closed loop system of seals, ducts and a compressor that reinjects the natural gas into the process or the natural gas pipeline. The VRU shall be operational at least ninety-five percent of the time the facility is in operation, resulting in a minimum combined capture and control efficiency of ninety-five percent. The VRU shall be installed, operated, and maintained according to the manufacturer's specifications;

(c) still vent and flash tank emissions shall not be vented to the atmosphere; and

(d) the owner or operator of a glycol dehydrator shall install an EMT on the glycol dehydrator in accordance with 20.2.50.112 NMAC.

(4) an owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the uncontrolled actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.

C. Monitoring requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) dehydrator location and identification number;

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) amount of controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and identification number of the control device or process the emissions are being routed;

(f) date and results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(g) a copy of the glycol dehydrator manufacturer operation and maintenance recommendations.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.118 NMAC - N, XX/XX/2021]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO_x (ppmvd @ 3% O_2)	CO (ppmvd @ 3% O_2)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than one year after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC upon startup.

(4) The owner or operator of a natural gas-fired heater shall install an EMT on the heater in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NOx and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications and good engineering practices;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly;

(iv) optimizing total emissions of CO consistent with the NO_x requirement, manufacturer specifications, and good combustion engineering practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O_2 in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_X and CO emissions and O_2 concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_X or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring, inspection, maintenance, or repair event, the owner or operator shall scan the EMT and the required monitoring data shall be captured in accordance with this Part.

D. **Recordkeeping requirements:** The owner or operator shall maintain a record of the following:

(1) location of the heater;

(2) summary of the complete test report and the results of periodic testing; and

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date the inspection, testing, maintenance, or repair was conducted;

(b) name of the personnel conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O_2 in volume percent; and

(d) the results of the inspections and any the corrective action taken.

E. **Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.119 NMAC - N, XX/XX/2021]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. **Applicability:** Hydrocarbon liquid transfers located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC beginning one year from the effective date of this Part.

B. **Emission standards:**

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-eight percent when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.

(2) An owner or operator using vapor balance during a liquid transfer operation shall:

(a) transfer the vapor displaced from the vessel being loaded back to the vessel being emptied via a pipe or hose connected before the start of the transfer operation;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) ensure that connector pipes, hoses, couplers, valves, and pressure relief devices are maintained in a leak-free condition;

(d) check the liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Bottom loading or submerged filling shall be used for the liquid transfer.

(4) Connector pipes and couplers shall be maintained in a leak-free condition.

(5) Connections of hoses and pipes used during liquid transfer operations shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) Liquid leaks that occur shall be cleaned and disposed of in a manner that prevents emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(7) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall visually inspect the transfer equipment during a transfer operation to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

(2) The owner or operator of a liquid transfer operation controlled by a control device must follow manufacturer recommended operation and maintenance procedures for the device.

(3) Tanker trucks and tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:

(a) method 27 of appendix A of 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of five minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H_2O (18 inches H_2O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H_2O (six inches H_2O) gauge. The maximum allowable pressure and vacuum changes (Δp, Δv) are shown in table 1 of 20.2.50.120 NMAC.

Table 1 - ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gallons)	Allowable vacuum change (Δv) in five minutes, mm H_2O (inches H_2O)	Allowable pressure change (Δp) in five minutes, mm H_2O (inches H_2O)
< 3,785 (< 1,000)	64 (2.5)	102 (4.0)
3,785 < 5,678 (1,000 < 1,500)	51 (2.0)	89 (3.5)
5,678 < 9,464 (1,500 < 2,500)	38 (1.5)	76 (3.0)
> 9,464 (> 2,500)	25 (1.0)	64 (2.5)

(b) pressure test the tanker truck or tanker railcar tank's internal vapor valve as follows:

(i) after completing the tests under Subparagraph (a) of Paragraph (3) of Subsection C of 20.2.50.120 NMAC, use the procedures in method 27 to re-pressurize the tank to 460 mm H_2O (18 inches H_2O) gauge. Close the tank's internal vapor valve, thereby isolating the vapor return line and manifold from the tank.

(ii) relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After five minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable five-minute pressure increase is 130 mm H_2O (five inches H_2O).

(4) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the location of the storage vessel and if using a control device, the type, make, and model of the control device:

(2) The owner or operator shall maintain a record of the inspections and testing required in Subsection C of 20.2.50.120 NMAC and shall include the following:

(a) the time and date of the inspection and testing;

(b) the name of the personnel conducting the inspection and testing;

(c) a description of any problem observed during the inspection and testing; and

(d) the results of the inspection and testing and a description of any repair or corrective action taken.

(3) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.120 NMAC - N, XX/XX/2021]

20.2.50.121 PIG LAUNCHING AND RECEIVING:

A. Applicability: Pipeline pig launching and receiving operations located within or outside of the property boundary of wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. Emission standards:

(1) Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that prevents emissions to the atmosphere; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton per year of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.

(2) The owner or operator of pig launching and receiving operations shall inspect the equipment for a leak using RM 21 or OGI immediately before the commencement and immediately after the conclusion of the pig launching or receiving operation, and according to the requirements in 20.2.50.116 NMAC.

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of pig launching and receiving operations shall maintain a record of the following:

(a) the pigging operation, including the date and time of the pigging operation and the type and volume of liquid cleared;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

(c) the type of control device and its location, make, and model.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

(3) An existing natural gas-driven pneumatic controller at a site with access to commercial line electrical power, and any existing natural-gas driven pneumatic controller at a transmission compressor station or a natural gas processing plant, shall comply with this Section within six months of the effective date of this Part.

(4) At sites that do not have access to commercial line electrical power, owners and operators shall retrofit their fleet of existing natural gas-driven pneumatic controllers according to the following schedule:~~shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:~~

TABLE 1. REQUIREMENTS FOR EXISTING NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS AT WELLHEAD SITES AND TANK BATTERIES.

Total Historic Percentage of Liquids Production at Facilities with Non-Emitting Controllers	**Conversion Required by December 31, 2023**	**Maximum Percentage Requirement by December 31, 2023**	**Additional Conversion Required by May 1, 2025**	**Maximum Percentage Requirement by May 1, 2025**	**Conversion Required by May 1, 2027**	**Maximum Percentage Requirement by May 1, 2027**
>75%	+10	92%	+8%	94%	+3%	96%
60–75%	+15	85%	+10%	93%	+7%	95%
40–60%	+20	75%	+18%	85%	+12%	92%
20–4 0%	+30	60%	+25%	78%	+15%	90%
0–20%	+35	50%	+25%	75%	+25%	90%

TABLE 2. REQUIREMENTS FOR EXISTING NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS AT GATHERING AND BOOSTING STATIONS.

Total Historic Percentage of Non-Emitting Controllers	**Additional Percentage Required by May 1, 2023**	**Maximum Percentage Required by May 1, 2023**	**Additional Percentage Required by May 1, 2025**	**Maximum Percentage Required by May 1, 2025**
> 75 %	+15%	97%	+5%	98%
> 60-75%	+20%	90%	+10%	98%
> 40-60 %	+25%	75%	+20%	95%
> 20-40 %	+35%	65%	+25%	90%
0-20 %	+40%	55%	+35%	90%

~~Table 1 – WELLHEAD SITES, TANK BATTERIES, GATHERING AND BOOSTING FACILITIES~~

~~Total Historic Percentage of Non-Emitting Controllers~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2024~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2027~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2030~~
~~> 75 %~~	~~80%~~	~~85%~~	~~90%~~
~~> 60-75 %~~	~~80%~~	~~85%~~	~~90%~~
~~> 40-60 %~~	~~65%~~	~~70%~~	~~80%~~
~~> 20-40 %~~	~~45%~~	~~70%~~	~~80%~~
~~0-20 %~~	~~25%~~	~~65%~~	~~80%~~

~~Table 2 – NATURAL GAS COMPRESSOR STATIONS AND GAS PROCESSING PLANTS~~

~~Total Historic Percentage of Non-Emitting Controllers~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2024~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2027~~	~~Total Required Percentage of Non-Emitting Controllers by January 1, 2030~~
~~> 75 %~~	~~80%~~	~~95%~~	~~98%~~
~~> 60-75 %~~	~~80%~~	~~95%~~	~~98%~~
~~> 40-60 %~~	~~65%~~	~~95%~~	~~98%~~
~~> 20-40 %~~	~~50%~~	~~95%~~	~~98%~~
~~0-20 %~~	~~35%~~	~~95%~~	~~98%~~

(~~4~~5) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero.

(b) existing pneumatic controllers at sites with access to commercial line electrical power, and any existing pneumatic controller at a transmission compressor station or a natural gas processing plant, shall have an emission rate of zero.

(c) At sites without access to commercial line electrical power, existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 and 2 of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers that are permitted under Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC,~~necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas~~ shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of tables 1 and 2 of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

~~**(v)** if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, the owner or operator has satisfied the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.~~

~~**(vi)** if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.~~

(d) a pneumatic controller with a bleed rate greater than ~~six standard cubic feet per hour~~zero is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional engineer.

(~~5~~6) Standards for natural gas-driven pneumatic pumps.

(a) pneumatic pumps located at a natural gas processing plants shall have an emission rate of zero.

(b) pneumatic pumps located at a wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) owners and operators of pneumatic pumps located at wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device.

(~~6~~7) The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) Pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

(2) The owner or operator of a pneumatic controller subject to the deadlines set forth in table~~s~~ 1 ~~and 2~~ of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject controller at each facility.

(3) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall, on a monthly basis, scan the controller and conduct an AVO inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC. During instrumental inspections, operators shall use Method 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 NMAC to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC. Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the department unless the owner or operator fails to determine whether the pneumatic controller is operating properly, perform any necessary response, or keep required records, or submit reports in accordance with the rule.

(5) The EMT shall be linked to a database that contains the following:

(a) pneumatic controller identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and

(e) design annual bleed in standard cubic feet per year.

(~~5~~6) The owner or operator of a pneumatic pump with a bleed rate greater than zero shall, on a monthly basis, scan the pump and conduct an AVO inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

(~~6~~7) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Pneumatic controllers and pumps with a natural gas bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

(2) The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a pneumatic controller subject to the requirements in table~~s~~ 1 ~~and 2~~ of Paragraph (~~3~~4) of shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.

(5) The owner or operator shall maintain an electronic record for each pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:

(a) pneumatic controller identification number;

(b) inspection dates;

(c) name of the personnel conducting the inspection;

(d) AVO inspection result;

(e) AVO level discrepancy in continuous or intermittent bleed rate;

(f) maintenance date and maintenance activity; and

(g) a record of the justification and certification required in Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate ~~greater than six standard cubic feet per hour~~zero shall maintain a record in the EMT database of the pneumatic controller documenting why a bleed rate greater than ~~six scf/hr~~zero is necessary, as required in Subsection B of 20.2.50.122 NMAC.

(7) The owner or operator shall maintain a record in the EMT database for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

(9) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Subsection F of 20.2.50.116 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.122 NMAC - N, XX/XX/2021]

20.2.50.123 STORAGE VESSELS

A. Applicability: Storage vessels with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.123 NMAC.

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent no later than three years after the effective date of this Part.

(2) An existing storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent no later than one year after the effective date of this Part.

(3) A new storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup.

(4) A new storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent upon startup.

(5) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the uncontrolled actual annual VOC emissions decrease to less than two tpy.

(6) If a control device is not installed by the date specified in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

~~**(7)** The owner or operator of a new or existing storage vessel with a thief hatch shall install a control device that allows the thief hatch to open sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device shall only be engaged when an owner or operator are present and during an active ingress activity.~~

(8) The owner or operator of a new or existing storage vessel shall install an EMT on the storage vessel in accordance with 20.2.50.112 NMAC.

(9) An owner or operator complying with Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC. Owners or operators of storage vessels with a PTE or actual emissions less than or equal to 5 TPY of VOC may comply with these requirements through use of an alternative control technology approved by the department, so long as the technology shall have a combined capture and control of VOC emissions of at least ninety-five percent.

C. Storage Vessel Measurement Requirements

(1) The owners and operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after the effective date of this Part, and at any facilities that are modified on or after the effective date of this Part such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage vessel measurement system to determine the quantity of liquids in the storage tank(s).

(2) Owners and operators subject to the storage vessel measurement system requirements in this Subsection must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage vessel(s).

(3) Operators may inspect, test, and calibrate the storage vessel measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Paragraph (1) of this Subsection.

(4) The owner or operator must install signage at or near the storage vessel that indicates which equipment and method(s) are used and the appropriate and necessary operating procedures for that system.

(5) The owner or operator must develop and implement an annual training program for employees and third parties conducting activities subject to this Subsection that includes, at a minimum, operating procedures for each type of system.

(6) Owner or operators must retain records for at least two (2) years and make such records available to the department upon request, including:

(a) Date of construction of the storage vessel or facility;

(b) Description of the storage tank measurement system used to comply with this Subsection;

(c) Date(s) of storage vessel measurement system inspections, testing, and calibrations pursuant to Paragraph (3) of this Subsection;

(d) Manufacturer specifications regarding storage vessel measurement system inspections, and/or calibrations, if followed pursuant to Paragraph (3) of this Subsection; and

(e) Records of the annual training program, including the date and names of persons trained.

D~~C~~. **Monitoring requirements:** The owner or operator of a storage vessel shall:

(1) monitor on a monthly basis the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig). When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) scan the EMT and enter the required monitoring data in accordance with the requirements of 20.2.50.112 NMAC;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements in 20.2.50.112 NMAC.

E~~D~~. **Recordkeeping requirements:**

(1) The owner or operator shall, on a monthly basis, maintain a record in accordance with 20.2.50.112 NMAC for a storage vessel. The record shall include:

(a) the vessel location and identification number;

(b) monthly liquid throughput and the most recent date of measurement;

(c) the average monthly upstream separator pressure;

(d) the data and methodology used to calculate the PTE of VOC (the calculation methodology shall be department approved);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput in shall be verified by a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) A record of the inspection required in Subsection C of 20.2.50.123 NMAC shall include:

(a) the time and date of the inspection;

(b) the personnel conducting the inspection;

(c) a notation that the required leak check was completed;

(d) a description of any problem observed during the inspection; and

(e) a description and date of any corrective action taken.

(4) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. **Reporting requirements:**

(1) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2021]

20.2.50.124 WELL WORKOVERS

A. **Applicability:** Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. **Emission standards:** The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. **Monitoring requirements:**

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. **Recordkeeping requirements:**

(1) The owner or operator shall keep the following record for a workover:

(a) identification number and location of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the management practices used to minimize release of VOC before and during the workover; and

(g) calculation of the VOC emissions vented during the workover based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.

[20.2.50.124 NMAC - N, XX/XX/2021]

20.2.50.125 SMALL BUSINESS FACILITIES

A. Applicability: Small business facilities as defined in this Part are subject to the requirements of 20.2.50.125 NMAC.

B. General requirements:

(1) The owner or operator shall ensure that all equipment is operated and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available to the department upon request.

(2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an annual basis. The calculation shall be based on the actual production or processing rates of the facility.

(3) The owner or operator shall maintain a database of company-wide VOC and NO_x emission calculations for all subject facilities and associated equipment and shall update the database annually.

(4) The owner or operator shall comply with Paragraph (10) of Subsection A of 20.2.50.112 NMAC if requested by the department.

C. Monitoring requirements: The owner or operator shall comply with the requirements in Subsections C or D of 20.2.50.116 NMAC.

D. Repair requirements: The owner or operator shall comply with the requirements of Subsection E of 20.2.50.116 NMAC.

E. Recordkeeping requirements: The owner or operator shall maintain the following electronic records for each facility:

(1) annual certification that the small business facility meets the definition in this Part;

(2) calculated VOC and NO_x emissions from each facility and the company-wide VOC and NO_x emissions for all subject facilities;

(3) records as required under Subsection F of 20.2.50.116 NMAC.

F. Reporting requirements: The owner or operator shall submit to the department an initial small business certification within sixty days of the effective date of this Part, and by March 1 each calendar year thereafter. The certification shall be made on a form provided by the department. The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

G. Failure to comply with 20.2.50.125 NMAC: Notwithstanding the provisions of Section 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other requirement of 20.2.50.125 NMAC.

[20.2.50.125 NMAC - N, XX/XX/2021]

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS

A. Applicability: Produced water management units as defined in this Part are subject to 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this Part.

B. Emission standards:

(1) The owner or operator shall use best management and good engineering practices to minimize emissions of VOC from produced water management units.

(2) The owner or operator shall control VOC emissions from each produced water management unit to less than two tons per year.

C. Monitoring requirements: The owner or operator shall:

(1) calculate the monthly rolling 12-month total of VOC emissions in tons from each unit;

(2) monthly, monitor the best management and engineering practices implemented to reduce emissions at each unit to ensure their effectiveness; and

(3) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each produced water management unit:

(a) name or identification of the unit and UTM coordinates of the unit and county;

(b) a description of the best management and engineering practices used to minimize release of VOC at the unit; and

(c) a record of the monthly rolling 12-month total VOC emissions from each unit.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.126 NMAC - N, XX/XX/2021]

20.2.50.127 REQUIREMENTS FOR FLOWBACK VESSELS AND PREPRODUCTION OPERATIONS

(A) Applicability: Wells undergoing recompletions and new wells being completed at an existing wellhead site are subject to the requirements of 20.2.50.127 NMAC one year after the effective date of this Part. New wells constructed at a new wellhead site that commence completion or recompletion after the effective date of this Part are subject to the requirements of 20.2.50.127 NMAC.

(B) Emissions standards:

(1) The owner or operator of a well must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to an operating control device that achieves a hydrocarbon control efficiency of at least 95 percent. If a TO or ECD is used, it must have a design destruction efficiency of at least 98 percent for hydrocarbons.

(a) the owner or operator shall ensure that a control device used to comply with emission standards in the Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(b) flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is in compliance with 20.2.50.127.B(1)(a) NMAC prior to receiving flowback.

(c) the owner or operator shall use a vessel measurement system to determine the quantity of liquids in the flowback vessel(s).

(i) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

(ii) Opening the thief hatch or other access point if required to inspect, test, or calibrate the vessel measurement system or to add biocides or chemicals is not a violation of 20.2.50.115.H(1)(a)(i) NMAC.

(C) Monitoring:

(1) Owners and or operators of a well with flowback that begins on or after the effective date of 20.2.50 NMAC, must conduct daily visual inspections of the flowback vessel and any associated equipment, including

(a) visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

(b) visual inspection or monitoring of the control device to ensure that it is operating.

(c) visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open.

(D) Recordkeeping:

(1) The owner or operator of each flowback vessel subject to Paragraph (1) of Subsection B of Section 20.2.50.127 NMAC must maintain records for a period of five (5) years and make them available to the the department upon request, including

(a) the API number of the well and the associated facility location, including latitude and longitude coordinates.

(b) the date and time of the onset of flowback.

(c) the date and time the flowback vessels were permanently disconnected, if applicable.

(d) the date and duration of any period where the control device is not operating.

(e) records of the inspections required in Subsection C of Section 20.2.50.127 NMAC, including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

20.2.50.128~~7~~ PROHIBITED ACTIVITY AND CREDIBLE ~~INFORMATION PRESUMPTION~~EVIDENCE

A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible evidence or information obtained by the department or provided to the department by a third party indicates that a source is not in compliance with the provisions of this Part, that information may be used by the department for the purpose of establishing whether a person has violated or is in violation of this Part.

~~**C.** If credible information provided to the department by a member of the public indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.~~

[20.2.50.127 NMAC - N, XX/XX/2021]

HISTORY OF 20.2.50 NMAC: [RESERVED]

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

REBUTTAL TESTIMONY OF DAVID MCCABE, PH.D.

Q: Dr. McCabe, you submitted direct testimony in this matter on behalf of Clean Air Advocates[1], correct?

A: Yes. My direct testimony addressed two sections of the rule: proposed 20.2.50.122 NMAC, which sets forth proposed regulations for pneumatic devices, and proposed 20.2.50.123 NMAC, which sets forth proposed regulations for storage vessels. Each of our proposals, as I explained in detail in my direct testimony, strengthens the proposed rule and will result in reduced emissions of ozone precursors at a reasonable cost to industry.

Q: Dr. McCabe, can you please summarize the opinions you will give as part of your rebuttal testimony?

A: My rebuttal testimony will do the following: (1) summarize the agreement that Clean Air Advocates, Environmental Defense Fund, Center for Civil Policy, NAVA Education Project, and Oxy USA, Inc. ("Oxy"), have come to since our initial filings (the "Oxy Agreement"); (2) rebut the analysis prepared by Valor EPC ("Valor"), a consultant for the New Mexico Oil and Gas Association ("NMOGA"), showing that Valor is mistaken in its conclusion that the New Mexico Environment Department ("NMED") overestimated the cost of its proposed regulation of pneumatic controllers; (3) explain why Clean Air Advocates oppose certain modifications to the pneumatics provision proposed by NMOGA; (4) explain why Clean Air Advocates oppose the proposal of Kinder Morgan, Inc. ("KM") to exclude pneumatic devices located at transmission

[1] Conservation Voters New Mexico, Diné C.A.R.E., Earthworks, National Parks Conservation Association, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, 350 New Mexico, and 350 Santa Fe.

compressor stations from regulation under this rule; (5) explain why Clean Air Advocates oppose proposals from NMOGA and the Commercial Disposal Group that would weaken NMED's proposed regulation of storage vessels; and (6) explain why a comparison of oil-and-gas activity in Colorado and Oklahoma over the past decade shows that industry concerns about this rulemaking harming industry are overblown.

OXY AGREEMENT

Q: Dr. McCabe, I would first like to ask you about the agreement that Clean Air Advocates, Environmental Defense Fund, Center for Civil Policy, NAVA Education Project, and Oxy have come to since our initial filings. Can you describe the discussions among those parties and the agreements reached?

A: Yes. Our coalition of groups has come to certain agreements with Oxy. After the initial filings, Oxy approached Clean Air Advocates and the Environmental Defense Fund to see if we could find common ground. We met over the course of several weeks, and have agreed upon certain, but not all, provisions in the proposed rule.

We believe that this development is important because the provisions we have agreed to would significantly improve and strengthen the rule proposed by NMED. Oxy agreed to support four key proposals advanced by Clean Air Advocates, with certain modifications. These proposals would:

- Increase the frequency of leak detection and repair inspections at wellhead sites located within 1,000 feet of homes, schools, and businesses in order to better protect the health of frontline communities,
- Accelerate the replacement of venting pneumatic controllers at well production facilities,
- Require emissions from completions and recompletions of wells to be captured instead of vented or flared, and

- Require automatic vessel measurement systems on new storage vessels to minimize venting of emissions from those devices.

It is significant that a major oil and gas operator in New Mexico has agreed to these stronger provisions. Clearly, Oxy views them as technically and economically feasible. We hope the Environmental Improvement Board will take note of this key development.

Q: Focusing on pneumatics, what does the Oxy agreement provide?

A: We agreed to the following table to govern the transition to zero-emission controllers at wellhead sites and tank batteries:

TABLE 1. REQUIREMENTS FOR EXISTING NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS AT WELLHEAD SITES AND TANK BATTERIES.

Total Historic Percentage of Liquids Production at Facilities with Non-Emitting Controllers	Conversion Required by December 31, 2023	Maximum Percentage Requirement by December 31, 2023	Additional Conversion Required by May 1, 2025	Maximum Percentage Requirement by May 1, 2025	Conversion Required by May 1, 2027	Maximum Percentage Requirement by May 1, 2027
>75%	+10	92%	+8%	94%	+3%	96%
60–75%	+15	85%	+10%	93%	+7%	95%
40–60%	+20	75%	+18%	85%	+12%	92%
20–4 0%	+30	60%	+25%	78%	+15%	90%
0–20%	+35	50%	+25%	75%	+25%	90%

In addition, Oxy agreed that gas-driven pneumatic controllers should be included in each operator's leak detection and repair program. This is something that Colorado has required in the Denver Metro/North Front Range Ozone Nonattainment Area since 2018, and which it extended to the rest of the state beginning in 2020. This will reduce emissions from malfunctioning controllers.

Q: Does the Oxy Agreement result in a program for transitioning to zero-emission controllers that is more similar to the program adopted in Colorado earlier this year?

A: Yes. As I explained in my direct testimony,[2] there are three major differences between NMED's proposal and the provision adopted by the Colorado Air Quality Control Commission in February 2021. First, NMED's timeline is ***much*** slower than Colorado's timeline. To give an example, a Colorado operator of natural gas gathering compressor stations that currently has no non-emitting controllers would have to convert 45% of its controllers at those stations by May 2023. Under NMED's proposal, such an operator would only be required to convert 25% of its controllers by 2024, and would not be required to match the Colorado requirement until January ***2027***. This is far too long, given how cost-effective it is to retrofit these devices and the emissions reductions that will result.

Second, Colorado requires operators to achieve a particular increase in the percentage of zero-emission controllers by each compliance deadline, rather than requiring operators to achieve a fixed percentage. As I explained in my direct testimony, Colorado's structure is more efficient, more equitable to operators, and less likely to create arbitrary outcomes than NMED's proposal.[3]

Third, for oil-and-gas production facilities, Colorado requires operator achieve a certain percentage of their total liquids production (including both liquid hydrocarbons and produced water) from wellhead facilities without emitting controllers, as opposed to requiring operators to retrofit a certain percentage of controllers. For example, an operator that currently produces 10% of its statewide liquid production at well pads with no emitting pneumatics must covert well pads that account for an additional 15% of the operator's total liquids production to use non-emitting controllers by May 1, 2022.

The Colorado rule was the product of focused and detailed negotiation between environmental organizations and industry, and it provides an excellent model for New Mexico to

[2] *See* Direct Testimony of David McCabe, Ph.D. ("Direct Testimony") at 19–23.
[3] *See id.* at 17–19.

follow here. The Oxy Agreement makes this rule more similar to the Colorado rule by (1) accelerating the timeline for retrofits, although still providing additional time compared to what is provided by the Colorado rule, (2) requiring operators to achieve a particular ***increase*** in the percentage of non-emitting controllers, and (3) expressing the phase-out program for wellhead facilities in terms of the percentage of total liquids production that occurs at non-emitting facilities, rather than using the percentage of non-emitting controllers. As explained, the Oxy Agreement also includes leak detection and repair requirements for pneumatic devices, similar to those required in Colorado.

It is important to note that for any given percentage level or percentage conversion requirement, fewer pneumatic controllers will be converted to non-emitting when the program uses a liquids production metric than when the program uses a percentage of controllers as the metric. This is because some sites produce a disproportionately high quantity of an operator's total statewide liquids production. As part of the Oxy Agreement, we are supporting the switch to the liquids production metric for two reasons. First, the change in metrics is coupled with acceleration of the timetable for retrofits. Second, it is coupled with regular inspection of gas-driven controllers. The liquid production metric incentivizes operators to prioritize retrofits of sites with high liquids production. At these sites, intermittent pneumatic controllers will frequently actuate, and actuation is a source of emissions for these controllers. However, as described below and in my direct testimony, a large portion of emissions from pneumatic controllers is associated with malfunctions, and I am not aware of any evidence that emissions associated with controller malfunctions are correlated with controller actuation frequency. Therefore, it is appropriate to couple the prioritization of retrofits at sites with high liquids production (where emissions from ***properly operating controllers*** would be expected to be higher) with the inspection program (which will address emissions from ***malfunctioning controllers***).

Some parties have proposed switching the metric for production sites to liquids production, without accelerating the timetable for retrofits or requiring inspections of gas-driven controllers. This approach would actually ***weaken*** the proposed rule, and should not be considered.

Q: Is the Oxy Agreement superior to the pneumatics provision included in NMED's proposal?

A: Yes. The Oxy Agreement will result in a more rapid transition to zero-emission controllers than the NMED proposal. The Oxy Agreement will also ensure that this phase out occurs in a more efficient, more equitable way.

Q: Like the proposal that Clean Air Advocates supported in their direct testimony, the Oxy Agreement will require operators to phase out emitting pneumatic devices more quickly than the NMED proposal. Did any party submit evidence that the cost of retrofitting pneumatic devices increases if these retrofits occur in earlier years?

A: No. I did not see any party submit analysis suggesting that the total cost of the retrofit program increases if the retrofits occurred in earlier years. The costs may be incurred earlier, but the emissions benefits (as well as the increased revenue and maintenance savings) will also be realized earlier.

VALOR ANALYSIS

Q: NMOGA commissioned a paper from Valor entitled *NMAC 20.2.50.122, Natural Gas-Driven Intermittent Pneumatic Controller Emission Factor*. Did you review this paper?

A: Yes.

Q: Can you summarize it?

A: Valor contends that the emission factor for intermittent-bleed controllers used by NMED is incorrect. NMED used an emission rate of 13.5 standard cubic feet per hour ("scf/hr") for these controllers, which is the emission rate operators must use for reporting their greenhouse gas emissions under Subpart W of 40 C.F.R. Part 98. Valor contends that the Subpart W estimate is outdated, and that more recent studies show that intermittent-bleed controllers have a much lower emission rate. It notes that Colorado used an emission factor of 3.5 scf/hr in the development of its February 2021 rule for pneumatic controllers. Using this much lower emission factor, Valor estimates that the cost of the pneumatic controller replacement program is at least $7,213 per ton of VOC reduced, much higher than the $2,745 per ton estimated by NMED.

Q: Valor cites a memorandum you co-authored, is that correct?

A: Yes. Valor asserts that Colorado used the emission factor of 3.5 scf/hr "at the suggestion of several environmental/conservation groups (see Appendix A)." Appendix A is a memorandum that I co-authored with my colleague at Clean Air Task Force Lesley Fleishman entitled *Average Emissions from Intermittent-Vent Pneumatic Controllers as Reported by Allen et al.* (2015).[4]

Q: Does Valor use the findings of your memorandum appropriately?

A: No. The purpose of the memorandum was not to propose a new, general emission factor for intermittent-bleed controllers. The purpose of our memorandum was to explain why one

[4] Our memorandum is attached as Appendix A to the analysis entitled *"Valor EPC Study: NMAC 20.2.50.122, Natural Gas-Driven Intermittent Pneumatic Controller Emission Factor,"* by Adam T. Meyer (NMOGA Appendix A2).

particular paper, Allen et al. (2015), underestimated the emission rate for the intermittent-bleed controllers surveyed as part of that study. We explained that:

> . . . the average emissions for intermittent-vent controllers from Allen et al. (2015) is not directly comparable to the emissions factors from these other sources. Allen et al. (2015) labeled controllers empirically, "based on the pattern observed during measurement." In cases where controllers that were designed to bleed intermittently were functioning improperly and continuously bleeding gas, Allen et al. (2015) labeled the controller as 'continuous bleed' if the continuous bleed constituted the dominant source of emissions.

We explained that this approach "*systematically* biase[d] low their results for 'intermittent-vent controllers,' relative to average emissions from functional intermittent-bleed controllers, by labeling intermittent-bleed controllers that are high-emitting due to continuous leaks as continuous-vent controllers." We attempted to correct for this bias, and concluded that if intermittent controllers had been properly identified, the study would have reported an emission factor for intermittent controllers of at least 3.5 scf/hr, rather than the 2.2 scf/hr reported.

The purpose of our analysis was not to propose a general emission factor for intermittent-vent pneumatic controllers. Rather, it was to show that the 2.2 scf/hr emission factor that Allen et al. (2015) report is too low. I do not believe that 3.5 scf/hr is an appropriate emission factor for intermittent-vent pneumatic controllers in New Mexico.

Q: Is Valor correct that Colorado used an emission factor of 3.5 scf/hr for intermittent-vent controllers?

A: Yes, but that does not mean this is an appropriate emission factor to use in New Mexico. Together with colleagues, I designed and prepared the economic analysis used for the Colorado rule, which was primarily developed in negotiations between environmental organizations and industry. For that analysis, we concluded that 3.5 scf/hr was a low, but appropriate, emission factor for pneumatic controllers ***in Colorado***. Emission rates for intermittent-bleed controllers can differ from jurisdiction to jurisdiction, and there is reason to believe that emissions from these devices are significantly lower in Colorado than in New Mexico. As I explained in my direct testimony, intermittent controllers "are designed to emit only during the actuation cycle for the controller, but in the field, these devices frequently emit between actuations."[5] For example, Luck et al. (2019) reported that 63% of the intermittent controllers observed as part of that study were operating abnormally.[6] Emissions due to malfunctions or abnormal operations can dwarf the emissions that occur during normal operations. Accordingly, intermittent controllers at sites that are inspected frequently are likely to have a significantly lower emission rate than controllers that are inspected less frequently.

For a variety of reasons, I would expect to find a higher rate of malfunction in New Mexico than in Colorado. Most importantly, Colorado has implemented a comprehensive program to limit emissions from malfunctioning controllers. Since 2018, operators in Colorado's the Denver Metro/North Front Range Ozone Nonattainment Area (which includes roughly half the oil and gas wells in the state) have been required to inspect each gas-driven controller at a site, using an instrumental technique such as optical gas imaging, whenever they inspect the site for leaks and other improper emissions.[7] Beginning in 2020, these requirements were extended statewide.[8] Operators must determine whether any controller with observed emissions is operating properly,[9] and if they find that it is not operating properly, they must undertake measure to return the controller to proper operations.[10] New Mexico has no comparable program

[5] Direct Testimony at 5.
[6] Benjamin Luck *et al.*, *Multiday Measurements of Pneumatic Controller Emissions Reveal the Frequency of Abnormal Emissions Behavior at Natural Gas Gathering Stations,* Environ. Sci. Technol. Letters 6, 348–52 (2019). https://pubs.acs.org/doi/10.1021/acs.estlett.9b00158.
[7] 5 Colo. Code Regs. § 1001-9:D.III.F.2.a.
[8] *Id.* § 1001-9:D.III.F.2.b.
[9] *Id.* § 1001-9:D.III.F.2.g.
[10] *Id.* §§ 1001-9:D.III.F.2.h and D.III.F.3.

in place. Given this program, we would expect to find a lower portion of controllers malfunctioning in Colorado than in jurisdictions with no such program. And indeed, the Colorado Air Pollution Control Division Task Force Report found that "only" 5.6% of inspected intermittent controllers were operating improperly. Studies that looked at other jurisdictions have found higher malfunction rates.

Q: Do you agree with Valor's summary of recent measurements of emissions from intermittent-vent pneumatic controllers?

A: No, I do not. Valor summarizes the literature as such:

> Recent studies involving hundreds of measurements (References 6 through 8) have demonstrated that emissions from natural gas-driven intermittent pneumatic controllers are routinely as low as 0.32 scf/hr. These studies are summarized below:
>
> - 2014 Oklahoma Pneumatic Controller Study: measured 659 intermittent pneumatic controllers, reported 0.4 scf/hr average emission rate;
> - 2015 Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: measured 322 intermittent pneumatic controllers, reported 2.2. scf/hr average emission rate, and
> - 2016 Uintah Basin Pneumatic Controller Study: measured 77 intermittent pneumatic controllers, reported 0.32 scf/hr average emission rate.[11]

Valor states that the first study, of pneumatic controllers in Oklahoma, "measured 659 intermittent pneumatic controllers." That is not accurate. The study in question estimated emissions using engineering equations. Pneumatic controller emissions were ***not*** measured.[12]

The second study listed by Valor is Allen et al. (2015). As described above, Allen et al. (2015)'s analysis systematically underestimates emissions from intermittent vent pneumatic

[11] *"Valor EPC Study: NMAC 20.2.50.122, Natural Gas-Driven Intermittent Pneumatic Controller Emission Factor,"* at 1-2.

[12] Oklahoma Independent Petroleum Association. Pneumatic Controller Emissions from a Sample of 172 Production Facilities. November 2014, at 1-2. http://vibe.cira.colostate.edu/ogec/docs/Oklahoma/1418911081.pdf

controllers. Despite the fact the Valor cites and relies upon the memo I co-wrote detailing this exact issue, Valor reports the 2.2 scf/hr emission factor directly without qualifications.

The third study mentioned by Valor is Thoma et al. (2017). This study presented many insights about the factors and issues that determine emissions from pneumatic controllers, but unfortunately, it was not based on a random sample of pneumatic controllers or sites. As the paper concludes,

> Due to the high percentage of IPCs [intermittent pneumatic controllers] and their generally low actuation volumes and rates, the overall emission profile of PC [pneumatic controller] systems in the Uinta Basin was determined in large part by the frequency of occurrence of malfunctioning PC systems. For the definitions employed here, this malfunction rate was found to be 14% with these PC systems emitting at levels four times the study average. With sites access provided by the cooperators, it is difficult to determine if the observed malfunction rate or associated emissions is representative of the basin. Underestimates of malfunction rate and/or the average level of emissions from malfunctioning PC systems could increase the basin average PC emission rate significantly from the levels observed in this study. Future work in the Uinta Basin should focus on randomized sampling in an attempt to more accurately characterize malfunction rates and levels of emissions.[13]

In summary, none of the calculated emission factors that Valor presents are appropriate estimates of emissions from intermittent pneumatic controllers in New Mexico.

Q: Was Valor internally consistent in its criticism of the Subpart W emission factors?

A: No. First, while Valor criticizes the Subpart W emission factor for intermittent-bleed controllers as "outdated" and recommends that NMED use the emission rate used in the Colorado rulemaking, it did not level the same criticism with respect to the Subpart W emission factors for low-bleed controllers. The emission factor used in Colorado—5.1 scf/hr—is much higher than the Subpart W emission factor for low-bleed controllers at production facilities, 1.39

[13] Thoma, E. D., et al. Assessment of Uinta Basin Oil and Natural Gas Well Pad Pneumatic Controller Emissions. *J. Environ. Prot.* 8:394. 2017, at 413. https://www.scirp.org/journal/paperinformation.aspx?paperid=75669.

scf/hr. The 5.1 scf/hr figure used in the Colorado analysis is from Allen et al. (2013).[14] As described in my direct testimony, Allen et al. (2013) actually presents a lower emission factor than other recent studies of low-bleed controllers, and thus using the 5.1 scf/hr emission factor might be an underestimate.[15] If Valor had used the Colorado emission factors for low-bleed controllers, it would have reported a lower cost per ton of VOC reduction than it did.

Q: So, do you believe it is appropriate to use the Subpart W emission factor for intermittent controllers in New Mexico?

A: Yes, I do. It has proven very difficult to measure emissions from intermittent controllers, given the high frequency of malfunctions, the many points from which emissions can potentially occur, and the variability of intermittent pneumatic controller function, installation/configuration, and other factors. For example, in order to get accurate emissions measurements from intermittent controllers, Luck et al. (2019) found that it was necessary to install a flow meter on the line supplying gas to the pneumatic controller and measure the amount of gas flowing to the controller over a period of more than 24 hours. Measurements conducted for a shorter time would lead to less accurate assessment of controller emissions.[16] What is clear about these devices is that they malfunction quite frequently, leading to emissions above the level that the device is designed to emit—often well in excess of that level.

While we recommended using a lower emissions factor for intermittent controllers in Colorado, that recommendation was informed by the fact that Colorado has required operators to inspect controllers for several years. Such a program is not in place in New Mexico. In my

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[14] David T. Allen, et al., *Measurements of methane emissions at natural gas production sites in the United States*, 110 Proc. Natl. Acad. Sciences (USA) 17768 (2013), www.pnas.org/cgi/doi/10.1073/pnas.1304880110.
[15] Direct Testimony at 6–7.
[16] Luck et al. (2019).

judgment, it is most appropriate for New Mexico to continue using the standard EPA emission factor for intermittent controllers, 13.5 scf/hr.

Q: Valor prepared a second paper, entitled *"NMAC 2.2.50.122, Pneumatic Controllers."* Did you review this paper?

A: Yes.

Q: Can you summarize it?

A: Valor contends that NMED and its consultant ERG greatly underestimated the costs of NMED's proposal to retrofit emitting pneumatic controllers.

Q: Do you agree with Valor's conclusion that NMED underestimated the costs of its retrofit program?

A: No. Most importantly, as discussed above, Valor uses an emission factor for intermittent-bleed controllers that is implausibly low for New Mexico. Using this emission factor, Valor contends that the annualized cost of reducing VOCs is $7,213/ton, $4,468/ton more than the $2,745/ton value reported by NMED. And as explained, Valor inconsistently chose not to update the emission factor for low-bleed controllers, continuing to use the Subpart W emission factor instead of the higher emission factor used in Colorado.

Beyond that, as I explained in my direct testimony, NMED likely ***overestimated*** the costs of retrofitting sites. First, it did not consider the increased revenue that operators receive by selling gas that would otherwise vent. Second, it did not consider the maintenance savings that operators realize after switching to electric or instrument-air compressors. As I discussed in my direct testimony, it is documented that these savings can be significant, since constituents of natural gas (especially the raw natural gas used on well pads and at gathering compressor stations) can be chemically incompatible with seals and other components of the controller, and droplets of liquids that form in components using raw natural gas will interfere with the operation of the controller. Third, NMED assumed that all sites with access to electricity would convert to instrument air systems, although electric controllers will typically be more cost-effective for sites with 20 controllers or fewer.[17] Fourth, NMED's model estimates the cost of retrofitting each device type across an operator's entire fleet. This overestimates costs because it implies that operators will conduct several, partial retrofits at each site. It is more cost-effective to retrofit all of the emitting pneumatic devices at a particular site at the same time, and I expect this is what operators will do. See Direct Testimony at 23–25.

Valor ignores all of the ways that NMED overestimated costs. It is especially puzzling that Valor ignored the fourth point. NMOGA acknowledged in its submission that retrofitting entire facilities is much more efficient than retrofitting one type of device at a time.[18] Indeed, since none of the proposed rules would require any operator to retrofit all controllers in an operator's inventory—or all of the sites in an operator's fleet—operators will prioritize retrofitting sites where it is less expensive to do so.

Q: Are there other problems with Valor's analysis?

A: Yes. Valor makes a variety of erroneous assumptions that lead it to overestimate equipment and installation costs. One particularly egregious problem with Valor's cost estimate is that it is based on air compression equipment that is sized to provide a much greater volume of compressed air to the pneumatic controllers at a site than those pneumatic controllers would need, based on Valor's claims about emissions from the controllers. Since pneumatic controllers

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[17] Carbon Limits (2016) [Clean Air Advocates' Ex. 4] at 23.

[18] See NMED Appendix B at 49 ("The most common replacement for pneumatic controllers is substitution of instrument air or line or generator-powered electrical controllers. In making such replacements, it is generally not feasible to replace a single pneumatic controller because of the cost of the supporting infrastructure . . . . Accordingly, for well production facilities and their associated tank batteries, planning at the facility level allows for orderly replacement rather than ad hoc replacement, which is more certain to achieve the desired reductions ***and will reduce*** **costs."**) (emphasis added).

use a compressed gas (natural gas or air) to operate, and this gas is vented as they operate, the volume of gas emitted by the controllers is equal to the volume of gas they require to operate. Further, controllers require about the same amount of natural gas or compressed air to operate: the air compressors needed to convert a site to compressed air only need to be able to compress a slightly higher volume of air (~25%) than the volume of natural gas vented by the controllers at the site.[19] Thus, the benefit of switching to air-driven controllers (that is, the volume of natural gas venting that is eliminated) is tied to the cost of the switch (the volume of air that is required to operate air-driven controllers), since a higher capacity air compression system costs more. However, the volume of gas that Valor claims that pneumatic controllers emit is completely inconsistent with the capacity of the air compressor Valor claims is necessary to operate those controllers with compressed air instead of gas. In other words, the vent rate Valor uses to estimate the cost of the NMED proposal is inconsistent with the rate it used to estimate the benefits of the proposal.

Q: Please explain what you mean when you say the vent rate Valor used to estimate the costs of NMED's proposal is inconsistent with the rate it used to estimate benefits?

A: While Valor argues that lower vent rates (3.5 scf/hr for intermittent vent controllers, 1.39 scf/hr for continuous vent controllers) are appropriate in estimating benefits, it presents cost information for air compressors that are many times larger than needed to operate controllers with these low vent rates. The NMED cost model for pneumatic controllers uses models of facilities with 10, 40, and 100 controllers per facility. (See "Pneumatics Reductions and Costs

[19] The gross air compression capacity required to deliver sufficient dry compressed air to operate a set of pneumatic controllers with air is, at most, about 25% greater than the volume of natural gas required to operate those controllers with natural gas. The ratio of dry air consumption to natural gas consumption for a controller varies from about 0.77 to 1, depending on the design of a controller. That is, some controllers would consume the same volume of dry air as of natural gas, while other controllers use ***less*** dry air than natural gas. However, for most air compression systems, around 25% of gross compressed air output is consumed by the process of drying the air, as is required before the air is sent to pneumatic controllers.

VOC 5-27-2021", tab "Study Data", cells A59-A61.) Valor's economic analysis uses costs for 5 horse power ("HP"), 15HP, and 60HP air compressors, respectively, to model the costs of compressed air systems at these model facilities.[20] The specifications and cost quotes that Valor appended to the study show the capacity of two of the air compressors they used to model costs. The specification sheet for one of the 15 HP compressors shows that it delivers about 35–40 scf per ***minute*** of compressed air.[21] 35 scf/minute is 2,100 scf/hr. With this capacity, and 40 controllers on site, the air compressor can deliver 52.5 sfc/hr of air per controller. Similarly, the specifications Valor lists for the 60 HP compressor shows that it delivers about 188 scf per ***minute*** of compressed air.[22] With this capacity, and 100 controllers on site, the air compressor can deliver ***113 sfc/hr*** of air per controller. Clearly, these calculations are not consistent with an assumption that an intermittent pneumatic controller only emits 3.5 scf/hr and a low-bleed controller only emits 1.39 scf/hr. So either Valor is overestimating costs, or it is underestimating emissions, or both.

Q: Are there other problems with Valor's cost analysis?

A: Yes. Valor presents numerous arguments that the equipment and installation costs for converting sites to non-emitting controllers will be higher than the costs that NMED uses. Unfortunately, I am unable to critique most of Valor's cost arguments because Valor's documentation is largely too opaque to critique. For example, Valor discusses sites that have no electricity on site but which have access to the grid. Presumably, these sites are proximate to grid power lines, but not hooked up. Valor uses a cost of $46,778 for "utility meters and installation" for these sites. The documentation for this is an invoice which lists several line

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[20] *"Valor EPC Study: NMAC 20.2.50.122, Pneumatic Controllers,* at 2.
[21] *Id.*, Appendix at 2.
[22] *Id.*, Appendix at 1.

items. The total cost shown on the invoice ($46,778) is largely accounted for by two unclear items: (1) "constr[uction] costs" ($32,353) for a project which is not described in any way, at a site that is not described in any way, and (2) an item which is either the cost of a "PT Meter-3 Phase UG" or a "PT metering fee" ($13,300). It is difficult to understand how the cost of hooking up electric service and installing a meter for 5–60 horsepower compressor (a 60-horsepower compressor would require about 150 amps of 3-phase 220-volt electricity) could cost almost $47,000.

Q: Let's talk about sites that do not have access to the grid. How did Valor estimate the cost of converting to zero-emission controllers at these sites?

A: Valor estimates that these sites would use an instrument air system that would cost (including installation) $117,180 for a 5 HP compressor and $138,118 for a 15 HP compressor. Valor's estimates include $12,447 for a solar panel, even though the system also includes a natural gas-fired generator. Although we endorse the use of this solar add-on, which reduces gas consumption and emissions, it is not required for the unit to operate and it would not be required by the rule; nevertheless, Valor includes this additional cost in its cost estimate.

Finally, Valor adds $39,060 for installation of the 5 HP unit and $46,039 for installation of the 15 HP unit. These units are pre-fabricated, "pre-commissioned" units. They are factory assembled and ready to be operated once they are placed on a pad. As shown on the quote for these units that Valor has provided, the manufacturer only charges $2,500 to commission the units on site. The operator simply has to hook up a fuel gas line to the unit and lines to carry compressed air from the unit to the pneumatic controllers at the site. It is difficult to imagine why doing this would cost $40,000, and Valor provides no explanation as to why it would cost this much.

Q: Are there other tools for estimating the cost of the proposed rule?

A: Yes. As described in my direct testimony, several years ago the consultancy Carbon Limits produced a report on zero-emitting technologies to replace gas-driven pneumatic controllers. As part of that work, Carbon Limits produced a spreadsheet tool for calculating the costs of converting the pneumatic controllers at a site to zero-emitting technologies, which we submitted as an exhibit to our direct testimony.[23] This spreadsheet tool was used to prepare the Conservation Groups' Initial Economic Impact Analysis for the Colorado rules,[24] which was the document used to estimate the costs and benefits of those rules.

Carbon Limits' report, and the cost tool, explicitly include reasonable estimates of all equipment required to operate a non-emitting technology. For example, for electric controllers at a site without access to the electric grid, the costs include solar panels, batteries, and control panels, as well as the electric actuators themselves. Furthermore, the costs include installation and labor costs. All cost assumptions used by Carbon Limits are disclosed in their report and/or the cost tool spreadsheet.

Even when accounting for the full cost of a installing a non-emitting technology at a site, and even using the lower emission factor for intermittent controllers that we concluded was appropriate for Colorado (which, as explained, would ***not*** be appropriate for New Mexico), the calculations based on the Carbon Limits Cost Tool showed that retrofitting wells sites and compressor stations with non-emitting controllers is cost-effective.[25] Therefore, we can be confident that, when using the higher emission factor for intermittent controllers (13.5 scf/hr)

[23] Carbon Limits (2016).
[24] Conservation Groups' Initial Economic Analysis for the Colorado Pneumatics Rules (2021) [Clean Air Advocates' Ex. 5].
[25] *Id.* at Tables 2, 4, 6, and 8.

which is appropriate for sites outside of Colorado, retrofit of these sites to remove gas-driven controllers will be highly cost-effective.

Q: Dr. McCabe, can you summarize your opinion as to the Valor cost analysis?

A: Yes. Valor's analysis is not valid because Valor

- did not account for the ways that NMED overestimated the costs of the rule, as documented in my direct testimony,
- underestimates the emissions from pneumatic controllers, and
- presents overestimates of equipment and installation costs.

This conclusion is further supported by the findings of Carbon Limits and the calculated cost-effectiveness of Colorado rule.

NMOGA REDLINE

Q: Do you agree with NMOGA's proposal to delete the requirement to immediately reach an emission rate of zero at existing facilities with access to electricity?

A: No, but we do believe that operators should be given some time to implement this requirement. Clean Air Advocates have proposed that sites with access to electricity, gas processing plants, and transmission compressor stations should all convert to non-emitting controllers within six months of the effective date of the rule. It has long been recognized that it is simpler, easier, and less expensive to convert sites with electricity to non-emitting controllers. There is no reason that operators of these facilities should be allowed to convert them to non-emitting controllers on the same schedule as sites without electricity. As I discussed in my direct testimony, several years ago Colorado required gas processing plants in the Denver Metro/North Front Range Ozone Nonattainment Area to be converted to zero-bleed within six months. This policy conforms with EPA's Control Techniques Guidelines for nonattainment areas, so it would quite appropriate as an aspect of the NMED rule, with its focus on VOC emission reductions.

Under NMOGA's proposed approach, operators would not be required to convert facilities with electricity for several years, or more. I presume that operators would prioritize converting facilities with electricity, because of the lower cost of doing so, over facilities without electricity. But the first deadline for facility conversion under NMOGA's approach would not be until early 2024. Furthermore, it is possible that an operator would not even need to convert all of its facilities with electrical grid power by the first deadline (if the percentage of sites with access to electric power is greater than the percentage of sites required to be non-emitting by the first deadline). In this situation, an operator would not be required to convert some facilities with electricity for many years. There is simply no technical or economic reason to allow operators to delay these simple retrofits for so long.

The rule should require operators to immediately and diligently work to convert facilities with grid electricity to non-emitting controllers. I believe that the six-month deadline we proposed in our initial submission is sufficient, given the Colorado precedent. If operators are able to document that they have a very high number of facilities with grid electricity and therefore it would be infeasible to convert those facilities to non-emitting controllers within six months, a one-year implementation period should be considered.

Finally, I note that in any case, operators would receive credit for converting these facilities to non-emitting controllers under the statewide retrofit program for existing controllers.

Q: Do you agree with NMOGA's proposal to exempt operators that produce less than fifteen barrels of oil equivalent per well per day from the requirements to retrofit facilities with non-emitting controllers?

A: No. Colorado does have an exemption similar to the one that NMOGA proposes. However, it would not be appropriate to adopt this exemption in New Mexico given the different context in New Mexico. First, NMOGA is proposing to add this exemption to NMED's proposed rule—which, as proposed, is already considerably weaker than the Colorado rule. Since the New Mexico rule, as proposed, is weaker, it is easier to comply with, and reduces emissions less, compared to the Colorado rule. In this context, it would be inappropriate to simply add in the exemption from the Colorado rule. (Even the strengthened retrofit requirements for well pads jointly proposed by the Clean Air Advocates, Environmental Defense Fund, and Oxy would not require as large a portion of operator's liquids production to be from retrofitted facilities by 2023 as the Colorado rule would require by that year.)

Second, the exemption would be more damaging in New Mexico than it is in Colorado, because a larger portion of New Mexico wells are owned by operators that would qualify for the exemption NMOGA proposes. Using data from a commercial database, we estimated that 187 operators in Colorado had production below 15 barrels of oil equivalent ("BOE") per well per day in 2019, and would thus be exempted from the pneumatics retrofit requirements. These firms operated 15,411 wells with non-zero production that year, which is 30% of the 50,791 wells with non-zero production that were operated that year in the state.

In contrast, based on our analysis of New Mexico production data obtained from the commercial database, I estimate that at least 312 firms produced less than 15 BOE per well per day in New Mexico in 2019. They operate over 32,000 wells which would thus be exempt from the retrofit requirements under NMOGA's proposal. This is more than half (57%) of the 56,494 oil and gas wells that were operating in New Mexico in 2019. So, if NMOGA's proposed exemption is adopted, it will exempt operators of twice as many wells from the New Mexico pneumatic retrofit program as are exempted from Colorado's program.

The firms that qualify for the exemption from the Colorado retrofit requirement for operators of low-producing wells are limited in size. Eight of the 187 exempt Colorado operators own more than 500 wells, but the largest of these eight operates 2,098 wells. Further, among these eight firms, none produced more than 8 BOE per well per day in 2019.

In New Mexico, much larger firms would qualify for the exemption NMOGA proposes, and some of these larger firms have relatively high production per well. New Mexico has nine firms with production below 15 BOE per well per day that own more than 500 wells; the largest (Hilcorp) operated over 11,400 wells in 2019. Of these nine firms, four (including Hilcorp) produce over 10 BOE per well per day. This is in contrast to Colorado, where none of the larger (500+ wells) firms that qualify for the exemption to the pneumatics retrofit rules produce more than 8 BOE per well per day.

In summary, NMOGA's proposed exemption would exempt operators of twice as many wells from the pneumatics retrofit requirements as are exempted by the Colorado rule. Compared to the firms exempted by the Colorado rule, the exempted firms in New Mexico would include larger firms, and large firms with relatively high production per well. These are firms that can readily afford to retrofit pneumatic controllers as would be required under our proposed rules, and they certainly could afford to comply with the much weaker retrofit requirements as proposed by NMED.

Therefore, the exemption that NMOGA proposes is far too broad.

Q: Do you agree with NMOGA's proposal to require operators to replace all high-bleed controllers by end of 2023?

A: Yes. Replacing high-bleed controllers is a proven and feasible measure to reduce unnecessary harmful pollution. Colorado required operators to do so, statewide, in 2014. (Operators in the Denver Metro/North Front Range Ozone Nonattainment Area had to do so even earlier.) I note that the deadline of the end of 2023 that NMOGA suggests is very lenient. Colorado required operators to replace high-bleed pneumatic controllers in just a few months.

Q: Do you agree with NMOGA's proposal to exempt pneumatic controllers located on temporary or portable equipment that is (A) on-site and in-use for 90 days or less or (B) used for well abandonment activities or (C) used through the end of flowback.

A: We do not oppose these provisions, but the general provision for temporary equipment used for 90 days or less should be modified to 60 days or less, to be consistent with the Colorado provisions for pneumatic controllers on temporary equipment.

KINDER MORGAN SUBMISSION

Q: Did you review the "Pre-Filed Non-Technical Statement" of Kinder Morgan, Inc. ("KM") and its affiliates?

A: Yes, I did.

Q: I understand that KM proposes to strike "transmission compressor stations" from 20.2.50.122.A NMAC, rendering these facilities exempt from all requirements applicable to pneumatic controllers. What is their rationale for proposing this change?

A: KM states: "Excluding transmission compressor stations from regulation of pneumatic controllers is justified based on, among other reasons, the low VOC content of the natural gas moved through Kinder Morgan's transmission compressor stations, which in turn limits the cost-effectiveness of the proposed emissions standards." KM Pre-Filed Non-Technical Statement at

28–29. KM states that its “average annual VOC content at all evaluated stations is less than 1%.” Exhibit V to KM Notice of Intent at 2.

Q: Why do Clean Air Advocates oppose KM’s proposal to exclude transmission compressor stations from the rule?

A: It is especially easy to retrofit pneumatic devices at transmission compressor stations because these stations are typically larger and have access to electric power. Indeed, NMED’s analysis indicates that ***all*** transmission compressor stations in the state have access to electric power.[26] KM did not introduce evidence of any transmission compressor stations that do not have access to electric power. To the contrary, KM’s expert, Leslie R. Nolting, testifies that KM has commercial power at its compressor stations ***and*** that it has emergency engines to sustain its most essential system needs in the event commercial power is lost due to inclement weather or electric grid equipment failures. KM Exhibit VI to Notice of Intent at 19.

Given that it is easy to convert to non-emitting controllers at these facilities, and performing these retrofits will reduce significant amounts of VOC and methane pollution,[27] these facilities should be required to perform these retrofits. As I explained in my direct testimony, six months is more than enough time to implement these retrofits. *See* Direct Testimony at 15–17.

KM’s argument simply ignores the methane that is emitted by pneumatic controllers, and the fact that retrofitting these facilities to eliminating venting pneumatics will substantially reduce harmful methane emissions. (Indeed, since there is a lower portion of VOC in the gas that pneumatics emit from transmission facilities, there is a higher portion of methane.) KM seeks to hide behind the VOC focus of this rulemaking to delay modernizing their facilities to

[26] Pneumatics Reductions and Costs VOC 5-27-2021 Excel Sheet.

[27] While KM is correct that pipeline-quality gas has a lower VOC content than gas further upstream, transmission compressor stations can still be a significant source of VOCs, and converting to zero-emitting pneumatic devices is a particularly cost-effective way to reduce emissions from these sources.

eliminate a large source of climate pollution. Such retrofits are already required for all transmission stations with more than 4,000 HP of compression in British Columbia (and must be complete in a few months). Substantial retrofits are also required at much smaller gathering compressor stations in Colorado, many of which do not have electrical power. And of course, retrofits at similar gathering and boosting stations in New Mexico will be required under the present rule, should it be adopted. Given these precedents, the larger typical size of transmission facilities, and the documented presence of electrical power at those sites, retrofitting them is clearly feasible and simply common-sense. Yet KM seeks to strike requirements for these retrofits at transmission facilities from the rule, forcing NMED and EIB to go through an additional rulemaking just to put in place a requirement that is obviously needed. EIB should reject this proposal.

STORAGE VESSELS

Q: NMED proposes to require emission controls at any existing storage vessel with a potential to emit at least two tons per year of VOCs. NMOGA proposes that this threshold be increased to 6 tons per year. Why do Clean Air Advocates oppose this change?

A: Several jurisdictions require control of emissions from storage tanks with VOC emissions lower than six tons per year. These include Colorado, with a threshold of two tons per year for new and existing tanks, and Pennsylvania, which has required the control of all new or modified tanks with VOC emissions above 2.7 tons per year since 2013. Finally, since 2012, the U.S. Environmental Protection Agency has required than any existing tank required to control emissions under NSPS OOOO or NSPS OOOOa must retain that control until emissions drop below four tons per year.

When Colorado lowered its threshold for control of tanks to two tons per year, the Colorado Air Quality Control Commission found that control of tanks emitting less than six tons of VOC per year is cost-effective. In fact, the Commission specifically found that control is cost effective even for the lowest emitting tanks in that cohort, those emitting between 2 and 3 tons per year of VOC.[28] Tanks with higher emissions are even more cost-effective to control.

Therefore, it would be inappropriate to raise the threshold for control of tanks from 2 tons per year to 6 tons per year.

Q: The Commercial Disposal Group proposes to create an exemption from emission controls in cases where supplemental fuel would be required to flare emissions from the vessel. Why do Clean Air Advocates oppose this proposal?

A: This proposal ignores the possibility that emissions can be captured and sold, even if the heat content is too low to flare. In fact, operators should be capturing and using flash gas from storage vessels regardless of the heat content. This eliminates waste, captures a valuable product, and eliminates emissions of CO_2 and NOx associated with flaring, which are cumulatively substantial.

ECONOMIC IMPACTS

Q: NMOGA's witness John Smitherman testifies that "If this rule is implemented as written, it can cause a huge number of wells to cease production, the economic impacts to the owners/operators, their employees, their families, the community, and the state can be profound."[29] Do you agree that this rule will negatively impact the oil and gas industry in New Mexico?

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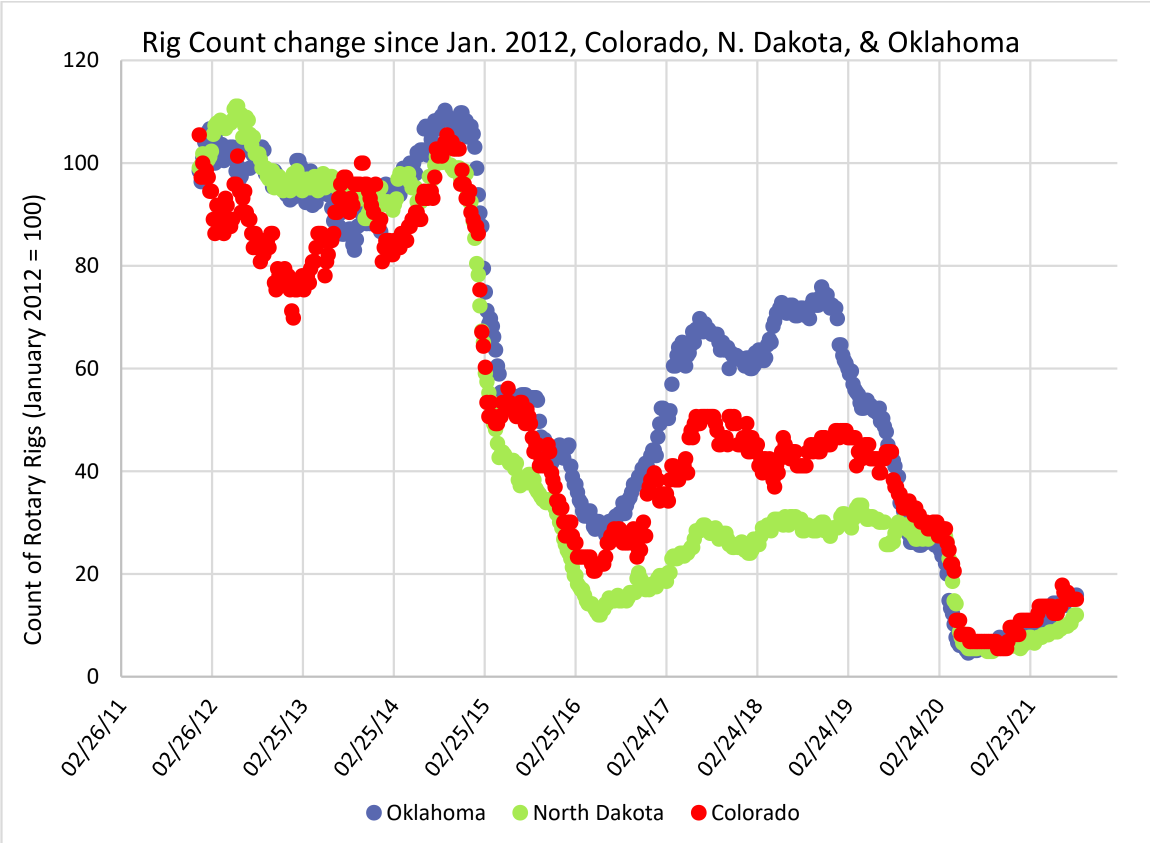
[28] Colorado found that control of condensate tanks with VOC emissions between 2 and 3 tons per year would cost $2,843 per ton of VOC emissions reductions. See Colorado Department of Public Health and Environment, Economic Impact Analysis (Final Analysis), Regulation Number 7, Meeting Date: December 17-19, 2019, Table 4.

[29] NMOGA Appendix A1, Direct Testimony of John Smitherman at 5.

A: No. We can be confident that these rules will not hamper the oil and gas industry in New Mexico in the way the NMOGA predicts. The rules that NMED proposed, and the strengthened rules that we propose, will require the New Mexico oil and gas industry to adopt measures very similar to those required in Colorado. Most of those rules were put in place in rulemakings in February 2014, December 2017, December 2019, and between December 2020 and February 2021.

Comparing the historical record of oil production (using data from the U.S. Energy Information Administration) and drilling (using rig count data from Baker Hughes) from Colorado to that from other states, it is clear that neither oil production nor drilling was hampered by the Colorado rules. The volume of production and, especially, the count of rigs vary tremendously over time, in response to the price of oil, other macroeconomic factors, and the evolution of production patterns in the U.S. (for example, the growth of activity in Permian basin in recent years, which has pulled capital investments away from other states). Because of these hugely influential, exogenous factors, it is helpful to compare Colorado's trajectory of drilling / rig count and oil production to other states that have not put in place similar, protective regulations to reduce air pollution from upstream oil and gas sites.

First, we consider the data for drilling / rig count, comparing Colorado's data since the beginning of 2012 to that from North Dakota and Oklahoma.

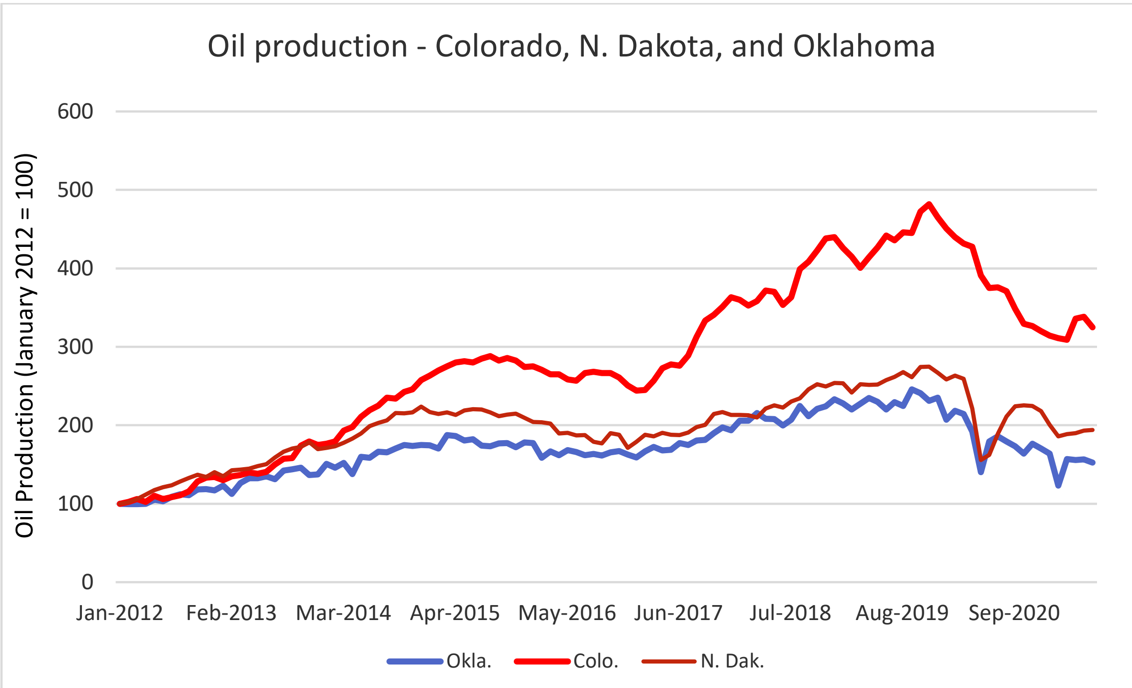


Since the size of the industry and the natural resources vary a lot between states (North Dakota and Oklahoma each had 180–190 rigs in January 2012, while Colorado only had 77), it is most informative to look at the ***changes*** in each state's rig count since the beginning of 2012. Therefore, the graph above shows, for each state, the ratio of the rig count in each state to that state's average rig count in January 2012, where the January 2012 average rig count is set at 100.

Clearly, drilling activity in Colorado has closely tracked activity in the other two states. After Colorado put rules in effect in February 2014, the rig count in Colorado grew—as it did in the other states that did not put in place rules to reduce unnecessary emissions. There are many changes in each state's drilling activity, but the states move very similarly. There is simply no evidence that drilling activity in Colorado dropped in response to the rules Colorado has put in place. And, in 2021, with all of the sets of rules in place (from 2014, 2017, 2019, and 2020–

2021), the ratio of present-day drilling to early 2012 drilling is the same or higher in Colorado as it is in Oklahoma and North Dakota.

The oil production data shows the same story. Quite simply, relative to January 2012 production, Colorado has outpaced North Dakota and Oklahoma for oil production.



Again, there is simply no evidence that the rules that Colorado has put in place have hampered oil production.

In summary, the evidence from drilling and production statistics shows that drilling activity and oil production in Colorado were not hampered by the protective rules that Colorado put in place over the past eight years. Given the similarity between the Colorado rules and the rules proposed by NMED and environmental stakeholders, we can be confident that adoption of these rules will not lead to the dire economic consequences that some stakeholders have predicted.

This concludes my testimony, which is accurate to the best of my knowledge.

/s/ David McCabe   September 7, 2021

David McCabe, Ph.D.   Date

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EDUCATION

University of California, Berkeley School of Public Health (Berkeley, CA) — 2014 – 2016
Master of Public Health, Environmental Health Sciences

Ithaca College (Ithaca, NY) — 2009 – 2013
Bachelor of Science, Environmental Science

TECHNICAL EXPERIENCE

Physicians, Scientists, and Engineers for Healthy Energy
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Senior Scientist — 2019 - present
- Leading research projects on the environmental, climate and public health dimensions of oil and gas development and other energy topics.
- Researching, drafting, and publishing peer-reviewed journal publications, technical reports, commentaries and expert testimony.
- Translating and disseminating scientific and technical information through briefings, webinars, presentations, blogposts and data visualization tools.
- Managing an online library of evidence-based primary research relevant to assessing the impacts of shale and tight gas development (i.e., Repository for Oil and Gas Energy Research, ROGER).
- Supporting research and community engagement on air quality monitoring projects using low-cost sensor technology (i.e., Richmond Air Monitoring Network).

Associate, Environmental Health Program — 2016 - 2019
- Researched, drafted, and published papers, reports and commentaries.
- Managed an online library of evidence-based primary research relevant to assessing the impacts of shale and tight gas development.

Office of Environmental Health Hazard Assessment (Oakland, CA) — May - Aug 2016
Research Assistant
- Evaluated toxicological and human epidemiological studies for carcinogenic endpoints for Proposition 65 program.

Natural Resources Defense Council (San Francisco, CA) — May - Sept 2015
Health Intern
- Investigated health hazard assessment methodologies used for chemicals in hydraulic fracturing fluids.
- Critiqued scientific findings and policy recommendations regarding well stimulation in California.

Ithaca Area Wastewater Treatment Facility (Ithaca, NY) — Nov 2013 - Jul 2014
Environmental Laboratory Intern
- Developed and implemented a sampling protocol for emerging organic pollutants at local drinking water and wastewater treatment facilities.

City of Ithaca Water Treatment Plant (Ithaca, NY) — May - Oct 2013
Water Quality Intern
- Performed daily drinking water quality tests and surface water sampling for water quality parameters and herbicide concentrations.

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Shonkoff SBC, **Hill LL**, Domen JK. *In Press*. Produced Water Quality: Implications for Human Health and the Environment. *California Council on Science and Technology,* Sacramento, CA.

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PRESENTATIONS

- **Mission Change Rulemaking – 600 Series**. September 8, 2020. Oral testimony before the Colorado Oil and Gas Conservation Commission (COGCC).
- **The Public Health Dimensions of California Wildfire and Wildfire Prevention, Mitigation and Suppression.** August 7, 2020. Public briefing.
- **The Public Health Dimensions of California Wildfire and Wildfire Prevention, Mitigation and Suppression.** August 5, 2020. California agency briefing.
- **Environmental Consulting at the Science-Policy Interface.** March 23, 2020. Invited lecture for ENVS 47500 - Advanced Environmental Seminar**,** Ithaca College (Ithaca, NY).
- **The Public Health Dimensions of Oil and Gas Development in California.** March 3, 2020. Invited webinar for California Climate Health Now (Oakland, CA).
- **Energy and Environmental Health.** December 3, 2019. Invited lecture for HED 655 - Environmental Health, San Francisco State University (San Francisco, CA).
- **Trends in Oil and Gas Waste Management in Pennsylvania, 1991-2017.** November 19, 2019. League of Women Voters' Shale and Public Health Conference (Pittsburgh, PA).
- **Energy and Environmental Health.** September 4, 2019. Invited lecture for ENVS 34001 - Topics in Pollution/Environmental Health and Medicine, Ithaca College (Ithaca, NY).
- **Evidence on the Carcinogenicity of Nitrite in Combination with Amines and Amides.** October 13, 2016. Poster presentation at Genetic and Environmental Toxicology Association of Northern California Fall Symposium (Oakland, CA).
- **Glyphosate Carcinogenicity: Is RoundUp Safe?** April 26, 2016. Poster presentation at Northern California Society of Toxicology Spring Symposium (Menlo Park, CA).
- **Evaluating Potential Heavy Metal Contamination from Ithaca Gun Company in the Fall Creek Delta.** April 4, 2013. Presentation at Ithaca College Whalen Symposium (Ithaca, NY).
- **Evaluating Potential Heavy Metal Contamination from Ithaca Gun Company in the Fall Creek Delta.** March 19, 2013. Poster presentation at Geology Society of America Northeastern Section 48th Annual Meeting (Bretton Woods, NH).

MEDIA

Media Coverage

- **E&E News.** November 26, 2019. 'Russian roulette'? EPA weighs release of drilling wastes. https://www.eenews.net/stories/1061647463.
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- **Environmental Health News.** April 23, 2019. More than 80 percent of waste from Pennsylvania's oil and gas drilling stays in the state: Report. https://www.ehn.org/more-than-80-percent-of-waste-from-pennsylvanias-oil-and-gas-drilling-stays-in-the-state-report-2635283061.html.

Blogposts

- **PSE Healthy Energy.** July 30, 2020. California Wildfires, Public Safety Power Shutoffs, and COVID-19: An Unprecedented Intersection of Public Health Risks. https://www.psehealthyenergy.org/news/blog/california-wildfires-public-safety-power-shutoffs-covid-19-intersection-of-public-health-risks/.
- **Meeting of the Minds.** September 5, 2019. The Power of Data from Urban Air Quality Monitoring Networks. https://meetingoftheminds.org/the-power-of-data-from-urban-air-quality-monitoring-networks-31545.
- **PSE Healthy Energy.** July 25, 2018.Why local air quality monitoring is important. https://www.psehealthyenergy.org/news/blog/air-quality-ab-617/.

Data Visualization Tools

- **PSE Healthy Energy.** 2019. Pennsylvania Oil and Gas Waste Mapping Tool. https://www.psehealthyenergy.org/pa-waste-map/.

TEACHING EXPERIENCE

Introduction to Environmental Health Sciences (PH 200C2) — UC Berkeley	2015
General Human Anatomy, Laboratory (IB 131L) — UC Berkeley	2014
Principles of Biology II (BIOL 12200) — Ithaca College	2013
Environmental Toxicology (ENVS 34001) — Ithaca College	2012

MANUSCRIPT REVIEW

Energy Research & Social Science	2020

CAA Ex. 24

STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC – *Oil and Gas Sector – Ozone Precursor Pollutants* **No. EIB 21-27 (R)**

REBUTTAL TESTIMONY OF LEE ANN L. HILL, MPH
PSE HEALTHY ENERGY

Q: Please state your name.

A: My name is Lee Ann L. Hill.

Q: Where are you currently employed and what is your position?

A: I am currently a senior scientist at Physicians, Scientists and Engineers (PSE) for Healthy Energy, a multidisciplinary, non-profit 501(c)3 energy science and policy research institute dedicated to supplying evidence-based scientific and technical information on the public health, environmental, equity and climate dimensions of energy production and use.

Q: What is your educational background?

A: I hold a Master of Public Health degree in environmental health sciences from the School of Public Health at University of California, Berkeley. I also hold a Bachelor of Science degree in environmental science from Ithaca College.

Q: Please describe your work experience, with particular attention to your work related to health risks and impacts from oil and gas facilities.

A: In my role at PSE, I conduct research on the environmental and public health dimensions of oil and gas development in the United States. Since 2016, I have supported and led PSE's work on the environmental health dimensions of oil and gas development in the United States. Much of my recent work has focused on examining the body of peer-reviewed literature on topics related to oil and gas development and human health, air quality, water quality, and waste management. My recent publications include studies on produced water management and chemical use associated with oil and gas development across multiple states, and the air quality and human health implications of oil and gas development and underground gas storage facilities. Intent on sharing research findings with relevant and diverse audiences, I have written commentaries, developed data visualization tools, and authored numerous peer-reviewed publications and technical reports.

Q: Is Clean Air Advocates' Exhibit 25 an accurate copy of your curriculum vitae?

A: Yes.

Q: Can you please summarize the opinions you will provide in your testimony?

A: Air pollutants hazardous to human health, the environment, and the climate — including greenhouse gases, hazardous air pollutants and criteria air pollutants — are emitted from upstream oil and gas development sites — herein referred to as oil and gas facilities. Air pollutants emitted directly from oil and gas facilities may also contribute to the secondary formation of air pollutants in the atmosphere which also pose risks to human health and the environment (e.g., ground-level ozone). Atmospheric concentrations of health-damaging air pollutants associated with oil and gas development generally decrease with distance from oil and gas facilities.

There is a reasonable degree of scientific certainty that living in close proximity to oil and gas facilities results in increased health risks and impacts from elevated air pollution levels and that these health risks are increasingly attenuated further from these operations. The public health risks and impacts associated with air pollutant emissions from oil and gas facilities that go unaddressed would be disproportionately experienced by people who live, work and go to school near oil and gas facilities. As such, emission reductions strategies should focus on sites in close proximity to human populations.

The increased frequency of LDAR inspections within 1,000 feet of "occupied areas"[1] is a targeted strategy to increase public health protections, which I strongly support. Specifically, I support the LDAR proximity proposal, which recommends:

- Quarterly LDAR inspections at oil and gas facilities located within 1,000 feet of "occupied areas" with a potential to emit (PTE) of less than 5 tons per year (tpy) volatile organic compounds (VOCs) (instead of annually at sites with PTE of less than 2 tpy and semi-annually at sites with PTE less than 5 tpy, proposed by the New Mexico Environment Department (NMED)), and
- Monthly LDAR inspections at oil and gas facilities located within 1,000 feet of "occupied areas" with PTE equal to or greater than 5 tpy VOC (instead of quarterly at sites with PTE more than 5 tpy, proposed by NMED).

Q: Have you provided a list of references that you have relied on in support of your testimony?

A: Yes, a list of references is provided at the end of my testimony.

Q: Specifically, have you reviewed the direct testimony of John Smitherman, New Mexico Oil and Gas Association ("NMOGA") Appendix A1 as his testimony pertains to proposed 20.2.50.116 NMAC, Equipment Leaks and Fugitive Emissions?

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[1] As defined at 20.2.50.7.GG NMAC in Joint Proposed Revised Amendments to Proposed 20.2.50 NMAC [Clean Air Advocates' Ex. 22]. This definition is based upon Colorado Air Quality Control Commission regulations, 5 C.C.R. 1001-9:D.II.A.16, and is interpreted to include residences, commercial workplaces, schools, hospitals and healthcare facilities, and outdoor recreation areas.

A: Yes.

Q: Would you summarize NMED's proposal with respect to the frequency with which leak detection and repair or LDAR inspections would be required?

A: For wellhead sites and tank battery facilities, NMED proposes:

- Annual inspections at facilities with PTE of VOCs of less than 2 tons per year,
- Semi-annual inspections at facilities with PTE of between 2 and 5 tons per year, and
- Quarterly inspections at facilities with PTE over 5 tons per year.

Q: What does NMOGA propose with respect to LDAR inspections?

A: In general, NMOGA proposes to reduce the frequency of LDAR inspections for oil and gas facilities.

Q: Before we discuss your response to the industry proposals, I'd like you to first discuss the risks and impacts to public health that emissions from oil and gas facilities pose. Which air pollutants are emitted from oil and gas facilities and how are people exposed to these pollutants?

A: Multiple air pollutants emitted from oil and gas facilities are associated with adverse impacts on human health and the environment. Broadly, air pollutants emitted from oil and gas facilities include greenhouse gases (e.g., methane); VOCs, many of which are hazardous air pollutants (HAPs); and criteria air pollutants (e.g., particulate matter (PM)).

Methane — the primary component of natural gas — is a potent greenhouse gas that captures 86 times more heat than carbon dioxide over the 20-year time horizon (US EPA, 2016a). Methane is emitted from various components or equipment at oil and gas facilities intentionally during venting, blowdown and other pressure release activities, or inadvertently via fugitive leaks and loss of containment events.

VOCs are a large class of organic compounds that include thousands of hydrocarbon gases and liquids that occur naturally in petroleum reservoirs and can volatilize given their specific chemical properties (i.e. higher vapor pressure or lower boiling point) (US EPA, 2014a). While some VOCs do not pose direct hazards to human health, many are classified as HAPs and are regulated under the Clean Air Act (US EPA, 2015a). A recent review of the peer-reviewed literature found that 61 HAPs were measured near upstream oil and gas sites or investigated from secondary data sources of upstream oil and gas sites available from across the United States (Garcia-Gonzales et al., 2019a). The top five HAPs most frequently detected near upstream oil and gas sites were benzene, toluene, ethylbenzene and xylenes and n-hexane. The health hazards associated with these HAPs that are also VOCs are discussed in the questions that follow below.

Criteria air pollutants are six pollutants commonly found in ambient air in the United States that cause adverse impacts to human health and the environment, and can cause property damage. Under the Clean Air Act, the US Environmental Protection Agency (US EPA) is required to set National Ambient Air Quality Standards and regulate concentrations of criteria air pollutants in ambient air (US EPA, 2014b). The primary criteria air pollutants directly emitted from oil and gas facilities include particulate matter (PM) and nitrogen oxides (NO_X). Both PM and NO_X emissions from oil and gas facilities largely stem from combustion sources including diesel or natural-gas powered engines found in trucks, drilling rigs, generators and boilers. PM and NO_X are also emitted through combustion of other on-site natural gas processes including flaring.

It is important to note that some air pollutants emitted directly from oil and gas facilities contribute to the secondary formation of air pollutants in the atmosphere that also pose risks to human health and the environment. For example, some VOCs, NO_X and sulfur oxides transform via atmospheric processes and form secondary PM. Additionally, upon interaction with sunlight, VOCs and NO_X can result in the formation of another criteria air pollutant — ground-level ozone (O_3), also commonly referred to as smog. The health hazards associated with select VOC compounds and criteria air pollutants are further described in the questions that follow below.

The composition, magnitude and intensity of air pollution emissions may vary by the source (e.g., equipment, component) or activity phase (e.g., well stimulation, oil and gas production) at oil and gas facilities. Sources of air pollutant emissions at oil and gas facilities include, but are not limited to, wells, pumps, generators, compressors, pneumatic devices, storage and separator tanks, surface impoundments, solid and liquid waste handling and from venting and flaring of gases. Activities at oil and gas facilities that emit pollutants into ambient air include, but are not limited to, the transport of equipment and materials to and from the well pad; well drilling; mixing, handling, and injection of oil and gas chemicals during well stimulation and routine maintenance operations; and management of recovered fluids, produced water, drill cuttings, and other waste products (Adgate et al., 2014; Johnston et al., 2019; NRC, 2014; Shonkoff et al., 2014).

Exposure to air pollutants associated with oil and gas facilities may occur when the source emits pollutants into the ambient air during routine or intentional operations (e.g., maintenance, venting) or unintentional or off-normal activities (e.g., fugitive leaks, loss of containment events) (Shonkoff et al., 2014; 2015). The concentrations of pollutants in air that result from these emissions influence the magnitude of exposure (Shonkoff et al., 2014). The primary route of exposure to air pollutants emitted from oil and gas facilities is via inhalation through the nose and mouth.

Exposure to air pollutants from oil and gas facilities may be acute (short term) or chronic (long term) depending on the activity phase(s) on site and the density of oil and gas development proximal to human populations. Acute exposures may occur from activities with short duration at an oil and gas facility (e.g., drilling) and when few or no additional oil and gas facilities reside near human populations. Intermittent spikes of health-damaging emissions from oil and gas activities and equipment have been observed (Allen, 2014; Brown et al., 2014), which can influence acute exposures over a shorter duration. Meanwhile, chronic exposures occur during longer phases of activity at the well pad (e.g., oil and gas production, produced water management) and when there is oil and gas development -- particularly dense oil and gas development -- occurring near human populations. Air pollutant emissions that influence regional air quality may also result in chronic exposures to health-damaging air pollutants for populations that are located both near and further away from oil and gas facilities.

Q: Please describe the risks and impacts to public health from exposure to volatile organic compounds or VOCs.

A: Emissions of benzene and other health-damaging VOCs associated with oil and gas facilities present well-understood health hazards. As described above, at least 61 HAPs were measured near upstream oil and gas sites or investigated from secondary data sources in the peer-reviewed literature (Garcia-Gonzales, 2019a). Below, I expand upon the health hazards associated with the five most commonly detected HAPs that are also VOCs: benzene, toluene, ethylbenzene and xylene and n-hexane. Each of these five compounds are naturally occurring in petroleum products (e.g., crude oil, natural gas) and therefore are often co-emitted with natural gas or emitted as products of combustion.

Benzene: Benzene is a known human carcinogen recognized by the US EPA and the International Agency for Research on Cancer (US EPA, 2016b; IARC, 2018). Given that carcinogenic compounds have no threshold for effects, there is no safe level of exposure to benzene (WHO, 2000). Acute inhalation exposure to benzene is associated with neurological effects (drowsiness, dizziness, headaches) and eye, skin and respiratory tract irritation. Chronic inhalation exposure to benzene is associated with noncancer hematological effects, such as aplastic anemia in which the body does not produce enough new blood cells (US EPA, 2016b).

Toluene: Toluene primarily impacts the central nervous system in humans as a result of acute and chronic exposures. Chronic exposure to toluene is also associated with irritation of the upper respiratory tract and eyes, dizziness and headache (US EPA, 2016c).

Ethylbenzene: The International Agency for Research on Cancer recognizes ethylbenzene as “possibly carcinogenic to humans" based on inadequate evidence in humans but sufficient evidence in experimental animals for the carcinogenicity of ethylbenzene (IARC, 2001). US EPA classifies ethylbenzene as “not classifiable as to human carcinogenicity” citing lack of available animal and human studies; however the last US EPA carcinogenicity assessment for ethylbenzene was conducted in 1991, predating IARCs more recent evaluation (ATSDR, 2010). Acute inhalation exposure to ethylbenzene can result in adverse respiratory effects, eye irritation, and neurological effects including dizziness (US EPA, 2016d). Chronic exposure to ethylbenzene has been noted for adverse effects on the liver, kidney, endocrine system and on development in animal studies (CalEPA OEHHA, 2016).

Xylenes: Acute inhalation exposure to xylenes can result in irritation of the eyes, nose, and throat, and neurological effects. Chronic inhalation exposure to xylenes results primarily in adverse central nervous system effects, including headache, dizziness, and fatigue (US EPA, 2016e).

N-hexane: N-hexane is an isomer of hexane. Acute inhalation exposure of hexane results in adverse impacts to the central nervous system, including dizziness and headache. Chronic inhalation exposure to hexane results in more severe neurological effects, including numbness in the extremities, muscular weakness, and blurred vision (US EPA, 2016f).

Q: What are the public health and environmental risks when VOCs and NO_X combine to form ground-level ozone?

A: VOCs contribute slightly over short and long time scales as greenhouse gases through their eventual decomposition into carbon dioxide. Additionally, some VOCs may be transformed by atmospheric processes to form secondary PM, which can contribute to reduced visibility (haze). In the presence of sunlight, VOCs react with NO_X in ambient air to form tropospheric (ground-level) ozone, commonly referred to as smog which also contributes to reduced visibility and other risks to health and the environment discussed below.

Ground-level ozone is a well-understood respiratory irritant that causes the muscles in the airways to constrict. Exposure to ground-level ozone can result in coughing and sore throat and can inflame and damage the airways. As such, ground-level ozone can exacerbate existing respiratory conditions, increase susceptibility to infection, and increase the frequency of asthma attacks. Adverse respiratory health effects resulting in exposure to ozone have been observed in healthy adults, but are more severe among sensitive subpopulations, including those with pre-existing lung diseases such as asthma, emphysema, chronic bronchitis, and chronic obstructive pulmonary disease (US EPA, 2015b). Ground-level ozone has been linked to increased emergency room visits for respiratory conditions in the United States (Strosnider et al., 2019).

Ground-level ozone can also adversely impact the environment. Sensitive vegetation and crops in forests, wildlife refuges, wilderness areas and agricultural fields may be impacted by ozone, particularly during the growing season (US EPA, 2015c; USDA, 2016). When ozone enters the leaves of sensitive plants, it can reduce photosynthesis, slow plant growth, and increase the risk of disease; damage from insects; damage from other pollutants; and harm from severe weather events. At the ecosystem level, the impacts of ground-level ozone on individual sensitive plants may result in loss of species diversity and changes to habitat and water and nutrient cycles (US EPA, 2015c). Ground-level ozone can also reduce crop yields (USDA, 2016).

Q: Do the risks and impacts to public health from VOCs, NO_X, and ground-level ozone increase the more a person is exposed to these pollutants?

A: Yes, chronic (long-term) exposure to VOCs, NO_X and ground-level ozone may result in longer lasting or more severe public health consequences.

Q: How do those health risks and impacts increase?

A: Generally, the duration of exposure is a key factor that influences the development of adverse health outcomes. Other key factors include the amount of pollutant an individual is exposed to and individual characteristics (e.g., age, sex, body weight) and genetic susceptibility. As compared to acute (short term) exposure, chronic exposure can result in more severe health impacts on the same target organ system or adverse health effects on different target organ systems. Additionally, duration of exposure and cumulative exposure over a lifetime, in addition to other factors, influence the likelihood of the development of cancer.

The adverse health effects associated with chronic exposure to specific VOCs associated with oil and gas development are described above. Chronic exposure to benzene is associated with adverse effects to the hematological system (e.g., bone marrow suppression) that may be more severe or longer lasting in duration as compared to short term impacts to the nervous system from acute exposure to benzene (e.g., dizziness) (CalEPA OEHHA, 2008).

While acute exposure to NO_X and ground-level ozone may cause short-term respiratory irritation and airway constriction, chronic exposure to NO_X and ground-level ozone are risk factors in the development of asthma, particularly in children, resulting in increased morbidity from respiratory diseases at the societal scale and over one's lifetime (US EPA, 2015b; 2016g). Even more severe, chronic exposure to NO_X and ground-level ozone are associated with premature mortality (Seltzer et al., 2018; Huang et al., 2021).

Q: Are people who live, work, go to school, or recreate near oil and gas operations at greater risk from exposure to air pollutants?

A: Yes. Populations in close proximity to oil and gas development may be disproportionately exposed to associated health-damaging air pollutant emissions. Therefore, populations in close proximity to oil and gas facilities are at greater risk of health risks associated with exposure to health-damaging air pollutants emitted from oil and gas facilities.

Q: Why are these people at greater risk and what are the increased risks and impacts?

A: While oil and gas development contributes to regional air quality impacts (Allen, 2016; Halliday et al., 2016; Helmig et al., 2014; Hildenbrand et al., 2016; Pétron et al., 2012; Pétron et al., 2014; Roy et al., 2014; Thompson et al., 2014), numerous air quality studies have reported that concentrations of various hazardous and other air pollutants are elevated in close proximity to active oil and gas development (Brown et al., 2014; Brown et al., 2015; Colborn et al., 2014; Macey et al., 2014; McKenzie et al., 2012; McKenzie et al., 2018; Rich & Orimoloye, 2016). Studies that include in situ air monitoring or rely on secondary air monitoring data collected at varying distances from upstream oil and gas sites also indicate that atmospheric concentrations of health-damaging air pollutants associated with oil and gas development decrease with distance from oil and gas facilities (McKenzie et al., 2018; Garcia-Gonzales et al., 2019b).

Three peer-reviewed studies published to date evaluate health risks associated with exposure to measured or modeled air pollutant concentrations by various distances from upstream oil and gas sites (McKenzie et al., 2012; McKenzie et al., 2018; Holder et al., 2019). Each of these three studies focused on oil and gas regions in Colorado and studies are discussed below in chronological order of publication date.

McKenzie et al. (2012) also found noncancer health risks associated with subchronic exposures and cancer risks were greater for residents living within ½ mile (2,640 feet) from oil and gas wells, as compared to those living beyond ½ mile (2,640 feet) for respiratory, neurological and hematological target organ systems. Increased risk was driven primarily by exposure to trimethylbenzenes, xylenes, and aliphatic hydrocarbons; slightly elevated excess lifetime cancer risk estimates were also driven by benzene and aliphatic hydrocarbon exposure (McKenzie et al., 2012).

McKenzie et al. (2018) found that lifetime excess cancer risks exceeded the U.S. EPA de minimis threshold (1 case in 1 million) out to 1,600 meters (5,249 feet). While cancer risk associated with exposure to benzene exceeded the U.S. EPA de minimis threshold across all distances examined, McKenzie et al. (2018) observed that lifetime excess cancer risk clearly increases with proximity from oil and gas development. Within 500 feet, McKenzie et al. (2018) also found potential for noncancer adverse health effects associated with acute exposures to benzene and alkanes for neurological, hematological, and developmental target organ systems.

Holder et al. (2019) clearly demonstrates that cancer risks and noncancer health risks associated with acute, subchronic and chronic exposures are reduced as distance from oil and gas sites increases. Holder et al. (2019) found potential for noncancer adverse health effects associated with acute exposures to 2-ethyltoluene, 3-ethyltoluene, toluene and benzene and for respiratory, nervous and hematologic (i.e., blood) target organ systems. These results applied to the highest exposed hypothetical individuals and were found to persist out to 2,000 feet for benzene exposure as well as for neurological and hematological effects. Excess lifetime cancer risk below the U.S. EPA de minimis threshold was only achieved at a distance beyond 1,800 feet from the well pad when considering various combinations of benzene exposure and risk estimate scenarios.

It is important to note that numerous health-damaging compounds associated with oil and gas development detected in the aforementioned air quality health risk assessment studies (e.g., benzene, ethylbenzene, toluene, among others) are associated with endocrine activity and effects potentially related to endocrine disruption, given peer-reviewed evidence that these compounds impact hormone production, mimic hormones, or inhibit hormone signaling (Bolden et al., 2018). While atmospheric concentrations of certain pollutants may be below acute or chronic health guidance values, it is important to note that exposure to low concentrations of oil and gas-associated chemical pollutants can impact the endocrine system, particularly during critical periods of development (e.g., fetuses, young children, etc.), which can influence numerous adverse health outcomes (Bolden et al., 2018).

In summary, peer-reviewed air quality health risk assessment studies indicate cancer and noncancer health risks increase with increasing proximity to oil and gas development sites (McKenzie et al., 2012; McKenzie et al., 2018; Holder et al., 2019).

Additionally, the body of epidemiological literature strongly supports that geographic proximity to active oil and gas development is an important risk factor for a variety of adverse health outcomes, including:

- **Respiratory outcomes** (Koehler et al., 2018; Rasmussen et al., 2016; Shamasunder et al., 2018; Peng et al., 2018; Willis et al., 2018; 2020; Johnston et al., 2021);
- **Cardiovascular outcomes and cardiovascular disease indicators** (McKenzie et al., 2019a; McAlexander et al., 2020; Denham et al., 2021);
- **Childhood cancer** (McKenzie et al., 2017);
- **Hospitalizations** (Denham et al., 2019; Jemielita et al., 2015); and
- **Adverse birth outcomes** (McKenzie et al., 2014; 2019; Casey et al., 2016; Busby and Mangano, 2017; Whitworth et al., 2017; Hill, 2018; McKenzie et al., 2019b;

Walker Whitworth et al., 2018; Apergis et al., 2019; Janitz et al., 2019; Gonzalez et al., 2020; Tran et al., 2020; Tang et al., 2021).

Epidemiological studies use aggregate measures to assess exposure to oil and gas development broadly, rather than focus on a specific mechanism (e.g., exposure to a specific air pollutant). As such, findings from these studies cannot definitively point to air pollution as the primary driver of adverse health risks and impacts. However, of these epidemiological investigations, studies focused on respiratory outcomes with findings reported by distance are perhaps the most applicable to discuss in the context of considering air pollutant emissions near oil and gas facilities. Seven studies evaluating respiratory outcomes and upstream oil and gas development are described below.

Two studies in California focus on respiratory outcomes and oil and gas development in Los Angeles. In the most recent study, Johnston et al., (2021), evaluated lung function among residents living near the oil development in Los Angeles between January 2017 and August 2019. Johnston et al. (2021) collected spirometry measurements for 747 residents (ages 10 to 85 years old) living within 1 km (3,281 ft) of active or idle oil development site. Reductions in lung function were observed the closer the residents lived to oil operations indicating a dose-response relationship, that is, lung function decreased for every 100 meters (328 ft) closer to the site. The differences in lung function were larger among the participants living near the active well site compared to the idle site. Even after adjusting for age, height, age-height relationship, weight, sex, race/ethnicity, proximity to freeway, recent cold/flu, asthma status, smoking status, indoor exposure to environmental tobacco smoke, and season, Johnston et al. (2021) found that study participants living nearby and downwind of oil and gas development sites in urban Los Angeles had reduced lung function compared to those living further away and upwind.

In another study focused in Los Angeles, California, Shamasunder et al. (2018) conducted household health surveys between March and May 2016 using questions from a validated health questionnaire within two 1,500 ft buffer zones surrounding two oil production sites. Self-reported physician-diagnosed asthma rates were elevated within both buffer zones compared to sub-county and county-level surveys. Asthma prevalence was higher in one buffer zone than Los Angeles County. While this study compared localized asthma rates to sub-county and county-level surveys, these comparisons do not consider competing sources of air pollution, other variables associated with asthma prevalence, or baseline demographic differences between these populations. This study also relies on self-reported data, which can be difficult to interpret.

Four studies in Pennsylvania report that upstream oil and gas development is associated with increased pediatric hospitalizations for asthma, increased rates of mild asthma exacerbations, and increased rates of lower respiratory symptoms, including mild asthma exacerbations (Rasmussen et al., 2016; Koehler et al., 2018; Peng et al., 2018; Willis et al., 2018).

Rasmussen et al. (2016) investigated the association between unconventional natural gas development and asthma exacerbations among asthmatic patients between 2005 and 2012. The authors found that those living next to the most dense areas of oil and gas production in the Marcellus Shale region had significantly increased odds of mild asthma exacerbation compared to those living near lower-density activity. This result was found to be significant during all four phases of development (pad development, drilling, stimulation, and production). In addition to mild asthma exacerbations, Rasmussen et al. (2016) also found that those in the highest quartile of residential unconventional natural gas development activity for all four phases (pad development, drilling, stimulation, production) had significantly higher odds of moderate and severe types of asthma exacerbations (emergency department visits, and hospitalizations, respectively) than those in the lowest quartile.

Koehler et al. (2018) used three exposure metrics to evaluate potential associations with mild asthma exacerbations in Pennsylvania. The authors compared two previous approaches (1) distance to nearest well drilled (<1 km, 1-2 km, >2km; <3,281, 3,281 - 6,562, >6,562 ft) and (2) an inverse distance metric based on the drilling phase (wells within 16 km, 52,493 ft); and a novel inverse distance-squared metric incorporating four phases of development (well pad development, drilling, stimulation, production) and compressor engine activities. Each exposure metric (highest exposure category compared to lowest) was associated with mild asthma exacerbations. Using previous methods and exposure categories, this study shows how different exposure metrics may yield similar findings.

Peng et al. (2018) also investigated the health impacts of unconventional natural gas development of Marcellus shale in Pennsylvania between 2001 and 2013 by merging well permit data from the Pennsylvania Department of Environmental Protection with a database of all inpatient hospital admissions. Authors found a significant association between shale gas development (counties with unconventional wells) and hospitalizations for pneumonia among the elderly, which is consistent with higher levels of air pollution resulting from unconventional natural gas development. The study is limited in that it relied on county-level exposure characteristics rather than focusing on residential distance to oil and gas wells.

Willis et al. (2018) evaluated the association between unconventional natural gas development and pediatric asthma hospitalizations in Pennsylvania between 2003 and 2014. The authors compared pediatric asthma hospitalizations among zip codes with and without unconventional natural gas development activity, a community-level exposure metric including drilling activity and air pollutant emissions reported by site. Odds of pediatric hospitalizations were consistently elevated in the highest exposure category compared to those unexposed. A 25% increase in odds of pediatric hospitalization for asthma was observed if a well was drilled within the same quarter. Presence of unconventional natural gas development within the same zip code over the entire study period was also associated with an increased odds of pediatric asthma hospitalization. These results suggest that unconventional natural gas development sites and associated air pollutant emissions are associated with increased risks of pediatric asthma hospitalizations.

Consistent with findings from studies in Pennsylvania and using similar methods as Willis et al. (2018), Willis et al. (2020) also observed an increased odds of pediatric asthma hospitalizations associated with natural gas development, conventional drilling and unconventional drilling activities, and increased well production volumes at the zip code level in Texas.

Q: What is your response to NMOGA's proposals to reduce the frequency of LDAR inspections at oil and gas facilities?

A: I do not support the reduction in frequency of LDAR inspections. Increased frequency of LDAR inspections can further reduce air pollutant emissions from fugitive leaks and loss of containment incidents at oil and gas facilities (Ravikumar et al., 2020), and therefore decrease health risks and adverse health impacts associated with releases of health-damaging air pollutants from these facilities.

Q: Have you have reviewed the "LDAR proximity proposal" proposed by Clean Air Advocates, the Environmental Defense Fund ("EDF"), and Center for Civic Policy and NAVA Education Project that would require oil and gas facilities located within 1,000 feet of "occupied areas" to conduct more frequent LDAR inspections?

A: Yes, the aforementioned groups propose that LDAR inspections at oil and gas facilities located within 1,000 feet of "occupied areas" be conducted:

- Quarterly at facilities with a PTE of less than 5 tpy VOCs (instead of annually at sites with PTE of less than 2 tpy and semi-annually at sites with PTE less than 5 tpy, as proposed by NMED), and
- Monthly at facilities with PTE equal to or greater than 5 tpy VOC (instead of quarterly at sites with PTE more than 5 tpy, as proposed by NMED).

Q: Have you reviewed the testimony from Hillary Hull, Director of Research and Analytics for the Environmental Defense Fund, which is Environmental Defense Fund (EDF) Exhibit SS.

A: Yes.

Q: In summary, what does Ms. Hull's analysis find with respect to the impact of the LDAR proximity proposal?

A: EDF's analysis found that the proposal would impact 3,365 or 7.7% of the well sites covered by NMED's proposed rule and will increase emissions reductions at those sites by 73%. EDF found that the proposal would result in an additional 3,600 tons of VOC reductions annually, and co-benefits would include reduction of an additional 14,300 tons of methane and 150 tons of hazardous air pollutants.

EDF's analysis also estimated that over 35,000 New Mexicans live within 1,000 feet of a well site regulated under NMED's proposed rule. And, of those, EDF estimated that over 2,700 are children under the age of 5; more than 4,500 are adults 65 years or older; more than 5,700 are living in poverty; and 19,000 are people of color, including over 5,800 Native Americans. That means that over half of New Mexicans living within 1,000 feet of a well site regulated under NMED's proposed rule are persons of color. Additionally, those living in close proximity to these well sites have health conditions that could be exacerbated by additional air pollution. EDF's analysis estimates that populations that live within 1,000 feet of an oil and gas facilities also include: more than 3,800 adults with asthma, over 2,200 adults with coronary heart disease, almost 2,600 with chronic obstructive pulmonary disease, and more than 1,200 adults who have experienced or are at risk of a stroke.

Q: What is your opinion with respect to the impact of the LDAR proximity proposal on the health of those living, working, and going to school close to oil and gas facilities?

A: Based on the estimated reductions of VOC, methane, and hazardous air pollutant emissions, I support the increased frequency in LDAR inspections for oil and gas facilities within 1,000 feet of "occupied areas". Targeted emission reductions strategies should focus on sites in close proximity to human populations, and the increased frequency of LDAR inspections within 1,000 feet of "occupied areas" is a targeted strategy to increase public health protections.

Furthermore, it is clear from EDF's demographic analysis near oil and gas facilities that impacts associated with these facilities, including but not limited to localized air pollution, are experienced by subpopulations that also face compounding vulnerabilities and socioeconomic burdens. Exposure to air pollution associated with oil and gas facilities is one of many factors — environmental or otherwise — that influence population health and every effort should be made to reduce exposures, and in particular among vulnerable subpopulations.

Q: What impact would NMOGA's proposals to decrease the frequency of LDAR inspections have on people who live, work, and go to school close to oil and gas facilities?

A: An overall decrease in frequency of LDAR inspections and delayed implementation of LDAR inspections would allow for fugitive leaks to go undetected and would result in emissions of methane and health-damaging air pollutants to go unmeasured, un-prevented and unmitigated. The public health risks and impacts associated with air pollutant emissions that go unaddressed would be disproportionately experienced by people who live, work and go to school near oil and gas facilities.

This concludes my testimony, which is accurate to the best of my knowledge.

Lee Ann L. Hill

Lee Ann L. Hill, MPH

9/3/2021
Date

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